

✓BKK



William A. Bonnet  
Vice President  
Government and Community Affairs

August 5, 2005

FILED  
2005 AUG -5 P 4: 49  
PUBLIC UTILITIES  
COMMISSION

The Honorable Chairman and Members of  
the Hawaii Public Utilities Commission  
Kekuanaoa Building  
465 South King Street  
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 04-0113  
HECO 2005 Test Year Rate Case

In accordance with Stipulated Prehearing Order No. 21727 in the above referenced proceeding, attached are twelve copies of HECO's rebuttal testimonies, exhibits and supporting workpapers.

Sincerely,

Attachments

cc: Division of Consumer Advocacy (3)  
Dr. Kay Davoodi (1)  
Randall Young, Esq. (1)  
Utilitech, Inc. (1)  
David Parcell (1)  
Sawvel and Associates, Inc. (1)

Hawaiian Electric Company, Inc.

Docket No. 04-0113  
Application for Approval of Rate Increases and  
Revised Rate Schedules and Rules

REBUTTAL TESTIMONIES AND EXHIBIT SPONSORSHIP LIST

<u>HECO RT-1</u>	<u>R. A. Alm</u>
TESTIMONY	Introductory Statement, Policy Matters
HECO-R-101	Public Hearing Statement
<u>HECO RT-2</u>	<u>C. M. Hazama</u>
TESTIMONY	Sales Forecast
HECO-R-201	Test Year 2005 Sales Forecast
HECO-R-202	Comparison of Direct Testimony and Rebuttal Testimony, GWH Sales Forecast
HECO-R-203	Comparison of May 2005 Sales & Customer Forecast Versus Rebuttal Test Year 2005 Estimates
HECO-R-204	Residential Recorded Sales, May 2005 Forecast Versus Rebuttal Test Year
HECO-R-205	Total System Sales
HECO-R-206	Comparison of 2005 versus 2004 June Year-To-Date Recorded Sales
HECO-R-207	Comparison of June Year-To-Date 2005 versus Test Year Forecast, Recorded Sales
HECO-R-208	Comparison of June Year-To-Date 2005 versus Test Year Forecast, Weather Normalized Recorded Sales

HECO RT-3 P. C. Young

---

TESTIMONY Electric Revenues and Other Operating Revenues

HECO-R-301 2005 Test Year Electric Sales Revenue

HECO-R-302 Estimate of Test Year Revenues

Schedule R – Residential Service

Schedule G – General Service Non-Demand

Schedule J – General Service Demand

Schedule H – Commercials Cooking, Heating, Air  
Conditioning and Refrigeration Service

Schedule PS – Large Power Secondary Voltage Service

Schedule PP – Large Power Primary Voltage Service

Schedule PT – Large Power Transmission Voltage Service

Schedule F – Public Street Lighting Service, Highway  
Lighting & Park & Playground Floodlighting

HECO-R-303 Electric Revenue, Comparison of Direct Testimony and Rebuttal  
Testimony Estimates at Present Rates

HECO-R-304 Total New Rider Customers Since Last Rate Case, Rider I, Rider  
M, Rider T, Schedule U

HECO-R-305 Derivation of Rate Adjustment for Calculation of Electric  
Revenue at Present Rates

---

HECO-R-306 Electric Revenue, Comparison of Direct Testimony and Rebuttal  
Testimony Estimates at Proposed Rates

HECO-R-307 Other Operating Revenues

HECO-R-308 Other Operating Revenue, Comparison of Direct Testimony and  
Rebuttal Testimony

HECO-R-309 Total Operating Revenue, Comparison of Rebuttal Testimony  
and CA and DOD Positions at Present Rates

HECO-R-310 Total Operating Revenue, Comparison of Rebuttal Testimony  
and CA and DOD Positions at Proposed Rates

HECO T-4 R. H. Sakuda

TESTIMONY	Fuel Expense, Fuel-Related Expense, Generation Efficiency, and Fuel Inventory
HECO-R-401	Test Year Fuel Expenses
HECO-R-402	Fuel Prices for 2005 Test Year, Weighted Average Fuel Prices
HECO-R-403	2005 Test Year Generation
HECO-R-404	Derivation of Fuel Expense
HECO-R-405	Test Year Fuel Related Expenses
HECO-R-406	Test Year Fuel Efficiency
HECO-R-407	Historical Fuel Efficiency
HECO-R-408	Test Year Fuel Oil Inventory
HECO-R-409	Derivation of Residual Fuel Oil Inventory Hawaiian Electric Company, Inc. AES Hawaii, Inc. Kalaeloa Partners H-Power Substation DG Generation
HECO-R-410	Low Sulfur Inventory 2000-2004
HECO-R-411	Diesel Oil Inventory 2000-2004
HECO-R-412	Derivation of Diesel Fuel Oil Inventory Derived on Daily Consumptions Basis
HECO-R-413	Days of Full Load Consumption
HECO-R-414	Historical Fuel Inventory Compared with Test Year Average Monthly Inventory

HECO RT-5 D. S. W. Ching

TESTIMONY	Purchased Power Expense
HECO-R-501	Total Purchased Power Expenses, Recorded 2004 and 2005 Test Year Estimate
HECO-R-502	Rebuttal Test Year Purchased Energy Forecast
HECO-R-503	Purchased Energy Forecast, Comparison of Direct and Rebuttal Test Year
HECO-R-504	2005 Test Year Energy Expense
HECO-R-505	Test Year Energy Expense, Comparison of Direct and Rebuttal Test Year
HECO-R-506	2005 Test Year Firm Capacity Increase
HECO-R-507	Test Year Firm Capacity Expense, Comparison of Direct and Rebuttal Test Year

<u>HECO RT-6</u>	<u>A. K. Fujinaka</u>
TESTIMONY	Other Production O&M Expense, Production Inventory
HECO-R-601	Other Production Operation & Maintenance Expenses
HECO-R-602	Other Production Operation & Maintenance Expenses, Labor and Non-Labor
HECO-R-603	Production Operation Expenses, Operations Adjustments
HECO-R-604	Production Operation Expenses, Maintenance Adjustments
HECO-R-605	Material & Supplies Inventory Production T&D
HECO-R-606	Comparison of HECO and Consumer Advocate Proposed, Other Production Operation & Maintenance Expenses
HECO-R-607	CA Proposed Adjustments to Production Operation Expenses
HECO-R-608	CA Proposed Adjustments to Production Maintenance Expenses
HECO-R-609	Production O&M Staffing, Update with Actuals as of June 30, 2005
HECO-R-610	Comparison of HECO Rebuttal Position and Consumer Advocate Adjustments for Other Production Operation & Maintenance Expenses
HECO-R-611	Comparison of HECO and Department of Defense Proposed, Other Production Operation & Maintenance Expenses
HECO-R-612	Areas of Agreement in Rebuttal Positions, Other Production Operation & Maintenance Expenses

HECO RT-8                      S. K. Yoshida

---

TESTIMONY	T&D Operation and Maintenance Expense, T&D Materials Inventory
HECO-R-800	Transmission and Distribution O&M Expense
HECO-R-801	Transmission and Distribution O&M Expense, Direct, Adjustment, Rebuttal
HECO-R-802	Transmission and Distribution O&M Expense, HECO versus CA Differences
HECO-R-803	Transmission and Distribution O&M Expense, Summary of HECO and CA Differences
HECO-R-804	Materials & Supplies Inventory Production T&D
HECO-R-805	Construction and Maintenance Department Staffing
HECO-R-806	System Operation Department Staffing
HECO-R-807	Engineering Department Staffing
HECO-R-808	Support Services Department Staffing

HECO RT-9                      D. S. Yamamoto

---

TESTIMONY	Customer Accounts Expense, Customer Deposits, Interest on Customer Deposits, Revenue Lag Days
HECO-R-900	Education Background and Experience
HECO-R-901	Customer Accounts Expense
HECO-R-902	Customer Deposits
HECO-R-903	Uncollectible Accounts Expense 2005
HECO-R-904	Customer Accounts Expense, Summary of HECO and CA Differences to HECO Direct Testimony Summary of HECO and DOD Differences to HECO Direct Testimony

HECO RT-10

A. K. C. Hee

---

TESTIMONY

Customer Service Expense, Demand-Side Management Program Expense, Energy Cost Adjustment Clause, Integrated Resource Planning Expense

HECO-R-1001

Customer Service Expense, Rebuttal Test Year 2005

HECO-R-1002

Customer Service Expense, Rebuttal Test Year 2005

HECO-R-1003

DSM Program Expense Summary, Account 910

HECO-R-1004

Revised Amount of DSM Expenses Proposed in Base Rates

HECO-R-1005

Non-DSM Customer Assistance Expense

HECO-R-1006

Informational Advertising Expense, Energy Efficiency and Conservation

HECO-R-1007

Customer Service Expense, DSM versus Non DSM Expenses

HECO-R-1008

Customer Service Expense Comparison, HECO Rebuttal versus CA Testimony

HECO-R-1009

Customer Service Expense Comparison, HECO Rebuttal versus DOD Testimony

HECO-R-1010

Customer Solutions Employee Count, Actual versus Test Year

HECO-R-1011

Correction to CA's and DOD's Adjustment for "Open" Positions

HECO-R-1012

2005 Test Year Energy Cost Adjustment Factors

Energy Cost Adjustment Filing Modified for DG, Current Effective Rates

Energy Cost Adjustment Filing Modified for DG, Proposed Rates

HECO-R-1013

Comparison of Rebuttal Testimony versus Direct Testimony Energy Cost Adjustment Factors

HECO-R-1014

Comparison of 2005 Test Year Energy Cost Adjustment Factor at Present Rates

HECO-R-1015

Determination of Composite Cost of Total (Central Station and DG) Generation for Avoided Cost Calculation Purposes

Derivation of Test Year 2005 Rebuttal Avoided Energy Cost Payment Rates

HECO-R-1016

Comparison of Rebuttal Testimony versus Direct Testimony Sales Heat Rate

HECO-R-1017

Comparison of 2005 Test Year Sales Heat Rate

HECO-R-1018

Actual Incremental IRP General Planning Costs, 1995-2004

HECO RT-11

G. A. Wikler

This witness has no rebuttal testimony and exhibits.

HECO RT-12

D. M. Violette

This witness has no rebuttal testimony and exhibits.

HECO RT-13

F. K. Yamauchi

TESTIMONY

Administrative & General Expense, Amortization of Kahe Unit 7  
Project Costs

HECO-R-1300

Educational Background and Experience

HECO-R-1301

Rebuttal Estimates for Administrative and General Expense  
Accounts

HECO-R-1302

Allocation of Ellipse Software Maintenance Fees  
Revised Calculation of the Ellipse Buy-Down Fee  
Amortization for TY 2005

HECO-R-1303

Administrative General Expenses Transferred, Account 922

HECO-R-1304

Employee Benefits Transfer, Account 926020

HECO-R-1305

Account 928 – Regulatory Commission Expenses

HECO-R-1306

Account 931 – Rent Expense

HECO RT-14

R. R. Harris

TESTIMONY

Insurance as Included in Administrative and General Expenses

HECO-R-1401

Comparison of HECO, CA, and DOD Test Year Estimates

HECO RT-15

J. K. Price

TESTIMONY

A&G Expenses, Employee Benefits

HECO-R-1501

Administrative & General Expenses – Employee Benefits

<u>HECO RT-16</u>	<u>T. S. Y. Sekimura</u>
TESTIMONY	Accounting Policy, Depreciation Expense and Accumulated Depreciation, King Street Lease, Total Average Number of Employees
HECO-R-1601	Summary of Changes to Plant, Depreciation Reserves and Depreciation Expense for TY 2005
HECO-R-1602	Revised TY 2005 Average Employee Count
HECO-R-1603	Total Positions Approved for Hiring in 2005 as of July 26, 2005
HECO-R-1604	Actual Employee Counts for December 2004 – July 27, 2005
HECO-R-1605	Comparison of June 30, 2005 Actual Employee Count with Revised TY December 2005 Forecast
HECO-R-1606	Estimated Wages & Benefits of Additional Approved Positions Not Included in TY 2005 Forecast
HECO-R-1607	King Street Office Building Lease Expense
HECO-R-1608	Accounting for Pensions
HECO-R-1609	Prepaid Pension Asset Balances, 1987–2005, 2004 Reconciliation of Pension Balances
HECO-R-1610	Standard & Poor's, Corporate Ratings Criteria 2005, Postretirement Obligations
HECO-R-1611	Moody's Investors Service, Rating Methodology, Analytical Observations Related to U.S. Pension Obligations, January 2003
HECO-R-1612	Standard & Poor's, Pension Liabilities Latest Red Flag for U.S. Utility Credit Ratings, June 5, 2003
HECO-R-1613	Moody's Reports: U.S. Pension Obligations May Increase Pressure on Credit Ratings, February 3, 2003
HECO-R-1614	Standard & Poor's, Corporate Credit Rating, Hawaiian Electric Company, Inc., May 31, 2005
<u>HECO RT-17</u>	<u>L. K. Okada</u>
TESTIMONY	Taxes Other Than Income Taxes, Income Tax Expense, Unamortized Net SFAS 109 Regulatory Asset, Unamortized Investment Tax Credit, Accumulated Deferred Income Taxes
HECO-R-1701	Taxes Other Than Income Taxes Charged to Operations
HECO-R-1702	Computation of Income Tax Expense
HECO-R-1703	State Capital Goods Excise Tax Credit
HECO-R-1704	Deferred Income Tax by Individual Items and Year End Balances
HECO-R-1705	SFAS 109 Reconciliation Regulatory Assets and Liabilities

<u>HECO RT-18</u>		<u>L. A. Nagata</u>
TESTIMONY	Plant Additions, Underground Cost-Sharing, Property Held for Future Use, Contributions in Aid of Construction, and Customer Advances	
HECO-R-1801	Plant Additions	
HECO-R-1802	Contribution in Aid of Construction	
HECO-R-1803	Customer Advances	
HECO-R-1804	Property Held for Future Use	
<u>HECO RT-19</u>		<u>G. T. Ohashi</u>
TESTIMONY	Rate Base	
HECO-R-1901	2005 Average Rate Base	
HECO-R-1902	Net Cost of Plant in Service	
HECO-R-1903	Unamortized Contribution in Aid of Construction	
HECO-R-1904	OPEB Liability	
HECO-R-1905	Working Cash Items, 2005, Items Requiring Working Cash, Items Providing Working Cash	
	Working Cash Items, 2005, At Present Rates, At Proposed Rates	
	O&M Non-Labor Payment Lag	
	Prepaid Pension Asset Balance	
	Other Post-Retirement Benefits Other than Pension	

HECO RT-20	R. A. Morin
TESTIMONY	Rate of Return on Common Equity
HECO-R-2001	Moody's Electric Utilities Beta Estimates Electric Utility Industry Beta Estimates Combination Gas & Electric Utility Beta Estimates
HECO-R-2002	Electric Utilities Historical Growth Rates
HECO-R-2003	Moody's Electric Utilities, DCF Analysis: Analysts' Growth Forecasts Investment-Grade Vertically Integrated Elec. Utilities, DCF Analysis: Analysts' Growth Forecasts
HECO-R-2004	Moody's Electric Utilities, DCF Analysis: Value Line Growth Projections
HECO-R-2005	Investment-Grade Vertically Integrated Elec. Utilities, DCF Analysis: Analysts' Growth Forecasts

HECO RT-22	P. C. Young
TESTIMONY	Cost of Service Study and Rate Design
HECO-R-2201	Summary of Class Revenue Requirements and Class Rates of Return at Present Rates and at Proposed Rates
HECO-R-2202	Summary of Class Rates of Return on Rate Base at Present Rates
HECO-R-2203	Summary of Class Rates of Return on Rate Base at Proposed Rates
HECO-R-2204	Proposed Allocation of Rate Increase by Rate Class
HECO-R-2205	Allocation of Rate Increase Based on Equal Class ROR
HECO-R-2206	Comparison of Class Revenue Requirements at Present Rates, At Proposed Rates and at Equal Rates of Return
HECO-R-2207	Summary of Cost Components by Rate Class at Proposed Rates
HECO-R-2208	Summary of Unit Cost Components by Rate Class at Proposed Rates
HECO-R-2209	Summary of Cost Components by Rate Class at Equal ROR
HECO-R-2210	Summary of Unit Cost Components by Rate Class at Equal ROR
HECO-R-2211	Summary of Allocation Factors

HECO-R-2212	Energy Loss Analysis by Rate Class
HECO-R-2213	Comparison of Class Revenues and Class Rates of Return at Present Rates Proposed Rates
HECO-R-2214	Marginal Energy Costs by Time-Of-Use Rating Period
HECO-R-2215	Comparison between Unit Embedded Costs and Unit Marginal Costs by Function
HECO-R-2216	Estimate of Test Year Revenues, Schedule R – Residential Service
HECO-R-2217	Estimate of Test Year Revenues, Schedule G – General Service Non-Demand
HECO-R-2218	Estimate of Test Year Revenues, Schedule J – General Service Demand
HECO-R-2219	Estimate of Test Year Revenues, Schedule H – Commercial Cooking, Heating, Air Conditioning and Refrigeration Service
HECO-R-2220	Estimate of Test Year Revenues, Schedule PS – Large Power Secondary Voltage Service
HECO-R-2221	Estimate of Test Year Revenues, Schedule PP – Large Power Primary Voltage Service
HECO-R-2222	Estimate of Test Year Revenues, Schedule PT – Large Power

<u>HECO RT-22</u>	<u>P. C. Young (Continued)</u>
HECO-R-2226	Bill Comparisons Under Present and Proposed Rates, Schedule R – Residential Service, Three Phase
HECO-R-2227	Bill Comparisons Under Present and Proposed Rates, Schedule G – General Service Non-Demand, Single Phase
HECO-R-2228	Bill Comparisons Under Present and Proposed Rates, Schedule G – General Service Non-Demand, Three Phase
HECO-R-2229	Bill Comparisons Under Present and Proposed Rates, Schedule J – General Service Demand, Single Phase
HECO-R-2230	Bill Comparisons Under Present and Proposed Rates, Schedule J – General Service Demand, Three Phase
HECO-R-2231	Bill Comparisons Under Present and Proposed Rates, Schedule H – Commercial Cooking, Heating, Air Conditioning, and Refrigeration Services, Single Phase
HECO-R-2232	Bill Comparisons Under Present and Proposed Rates, Schedule H – Commercial Cooking, Heating, Air Conditioning, and Refrigeration Services, Three Phase
HECO-R-2233	Bill Comparisons under Present and Proposed Rates, Schedule PS – Large Power Secondary Voltage Service
HECO-R-2234	Bill Comparisons Under Present and Proposed Rates, Schedule PP – Large Power Primary Voltage Service
HECO-R-2235	Bill Comparisons Under Present and Proposed Rates, Schedule PT – Large Power Transmission Voltage Service
HECO-R-2236	Bill Comparisons Under Present and Proposed Rates, Schedule F – Public Street Lighting, Highway Lighting and Park & Playground Lighting
<u>HECO RT-23</u>	<u>W. A. Bonnet</u>
TESTIMONY	Results of Operations, including Revenue Requirements, and Implementation of the Proposed Rate Increase
HECO-R-2301	Results of Operations 2005
HECO-R-2302	Results of Operations 2005 with IRP Cost Recovery Provision
HECO-R-2303	Reconciliation of Electronic Sales Revenue at Present Rates to Current Effective Rates Lost Margin Component of 2005 DSM Adjustments Lost Margin

REBUTTAL TESTIMONY OF  
ROBERT A. ALM

SENIOR VICE PRESIDENT  
PUBLIC AFFAIRS  
HAWAIIAN ELECTRIC COMPANY, INC.

Subject:   Introductory Statement  
            Policy Matters

INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert A. Alm and my business address is 900 Richards Street,  
Honolulu, Hawaii.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted written direct testimony and exhibits as HECO T-1, and HECO  
Exhibits 101 through 114.

Q. Did HECO present a statement at the public hearings held by the Commission?

A. Yes. HECO made a presentation at the public hearing held on Wednesday,  
January 12, 2005 in Honolulu. A copy of HECO's public hearing statement is  
attached as HECO-R-101.

Q. What is the scope of your rebuttal testimony in HECO RT-1?

A. My rebuttal testimony in HECO RT-1 summarizes:

- 1) HECO's rebuttal position in this proceeding,
- 2) The major issues between HECO and the Consumer Advocate ("CA") and  
the Department of Defense ("DOD"),
- 3) Certain policy matters related to this case, and
- 4) Other matters related to this proceeding.

Q. Has HECO made any changes in its witnesses since the submittal of its direct  
testimonies?

A. Yes. Since submittal of the Company's direct testimonies, Mr. Ernie Shiraki  
(HECO T-13) and Ms. Estrella Seese (HECO T-22) have retired. Mr. Shiraki's  
testimony pertaining to Administrative & General (A&G) Expenses has been  
adopted by Faye Yamauchi, Director of Cost Accounting. The remaining issues  
that are set forth in Mr. Shiraki's testimony have been adopted by Ms. Tayne

1           Sekimura. Ms. Yamauchi is providing rebuttal testimony as HECO RT-13 to  
2           address the issues raised by the CA pertaining to A&G Expense and Kahe Unit 7  
3           project costs. Ms. Yamauchi is also adopting a portion of Ms. Sekimura's  
4           testimony (HECO T-16) pertaining to Miscellaneous Administrative and General  
5           Expense and has incorporated rebuttal testimony pertaining to this area in HECO  
6           RT-13. Ms. Sekimura is providing rebuttal testimony (HECO RT-16) on issues  
7           raised by the CA pertaining to Employee Count, Depreciation, King Street  
8           Lease, and Accounting Policy. Ms. Seese's testimony, HECO T-22, has been  
9           adopted by Mr. Peter Young. Mr. Young is providing rebuttal testimony, HECO  
10          RT-22, to address issues raised by the CA and DOD pertaining to Cost of  
11          Service/Rate Design.

12                 In addition, Ms. Amy Ejercito is now the Vice President of Corporate  
13          Excellence. Ms. Ejercito's testimony, HECO T-9, has been adopted by Mr.  
14          Darren Yamamoto, Manager, Customer Service Department. Mr. Yamamoto is  
15          providing rebuttal testimony, HECO RT-9, to address matters raised by the CA  
16          and DOD concerning Customer Accounts Expense, Customer Deposits, Interest  
17          on Customer Deposits, and Revenue Lag Days.

18  
19                                 HECO REBUTTAL POSITION

20          Q.     What is HECO's rebuttal position?

21          A.     HECO's rebuttal testimonies and exhibits justify revenue requirements of  
22                 \$1,284,637,000, as shown in HECO-R-2301. (These amounts are based on May  
23                 1, 2005 fuel and purchased energy prices, and an 8.83% return on average rate  
24                 base and an 11.0 % return on common equity.) Given HECO's estimated  
25                 revenues at present rates of \$ 1,221,602,000, the amount of the total rate increase

1           that HECO has justified is \$ 63,035,000, or 5.20%, over present rates for the  
2           normalized 2005 test year. (See HECO RT-23 and HECO-R-2301.) Based on  
3           current effective rates (i.e., rates that are currently in effect for our customers) of  
4           \$1,233,760,000 (based on May 1, 2005 fuel oil and purchased energy prices), the  
5           amount of the increase in revenues is \$50,877,000, or 4.1%. HECO-R-2302. See  
6           Mr. William Bonnet's rebuttal testimony (HECO RT-23).

7           Q.     What is the difference between "present rates" and "current effective rates"?

8           A.     Revenues at present rates (and at proposed rates) are calculated without  
9           including revenues recovered through the Integrated Resource Planning Cost  
10          Recovery Provision ("IRP Clause"). Current effective rates are the rates  
11          currently in effect, which include revenues recovered through the DSM  
12          component of the IRP Clause for "lost margins". In addition, the IRP Clause  
13          also includes an IRP Planning Cost Recovery Adjustment to recover incremental

---

14          IRP planning costs (i.e., IRP planning costs not included in base rates.) In  
15          Decision and Order No. 18365 issued by the Commission on February 8, 2001 in  
16          Docket No. 99-0207 in Hawaii Electric Light Company, Inc.'s ("HELCO") last  
17          rate case, the Commission determined that, for that case, it would be appropriate  
18          for HELCO to recover incremental IRP costs through base rates. In an effort to  
19          be consistent with the decision issued in HELCO's last rate case, revenues at  
20          present rates also do not include the IRP Planning Cost Recovery Adjustment  
21          portion of the IRP Clause. As a result, part of the increase in base rates  
22          experienced by customers will be offset by the decrease in IRP Clause revenues.

23          Q.     What amount of current effective rates in the Results of Operations, proposed in  
24          rebuttal, relates to revenues recovered through the IRP Clause?

25          A.     HECO's estimated revenues at current effective rates for the 2005 test year

1 include revenues of \$12,158,000 from the IRP Clause, including \$11,479,000 for  
2 recovery of lost margins for demand-side management ("DSM") programs  
3 currently in effect, and \$678,000 for recovery of a normalized level of  
4 incremental IRP planning costs included in the rebuttal 2005 test year estimates.  
5 (See HECO-R-2303.) Revenues collected from customers already reflect these  
6 costs, thus this portion of the rate increase request, which shifts revenues from  
7 the IRP Clause to base rates, does not increase customer bills.

8 Q. How do the revenues from the IRP Clause included in current effective rates in  
9 rebuttal testimony compare to the IRP Clause revenues used in determining the  
10 current effective rates in direct testimony?

11 A. The IRP Clause revenues in current effective rates in direct testimony amounted  
12 to \$74,423,000, including \$23,744,000 for recovery of DSM program costs, lost

13 margins and shareholder incentives for DSM programs currently in effect, and  
14 \$678,000 for recovery of a normalized level of incremental IRP planning costs  
15 included in the test year expenses. (See HECO-2303). The amount related to  
16 incremental IRP planning costs included in the test year expenses is \$678,000.

1       A.     In HECO's direct testimonies, revenues at current effective rates included all  
2       revenues recovered through the IRP Clause, including the revenues to recover  
3       DSM, program costs, shareholder incentives and related revenue taxes, and not

4       just the revenues related to lost margins and IRP incremental costs.

5       Q.     Please describe how the IRP Clause operates, and summarize why all costs  
6       related to DSM programs were included in base rates in the application.

7       A     The IRP Clause is used to recover costs for integrated resource planning ("IRP")

1       A.     On March 16, 2005, the Commission issued Order No. 21698, separating  
2       HECO's requests for approval and/or modification of its existing and proposed  
3       DSM programs from the rate case proceeding into a new docket, the "Energy  
4       Efficiency Docket", Docket No. 05-0069. As a result, an estimated \$29 million  
5       in DSM program costs related to both the enhanced DSM programs and to the  
6       existing DSM programs have been removed from the rate increase request, based  
7       on the understanding that DSM program costs for existing DSM programs that  
8       are currently recovered through the IRP Clause will continue to be recovered  
9       through the surcharge, and there will be a mechanism to recover costs related to  
10      the new DSM programs that result from Docket No. 05-0069.

11     Q.     What is the result of the bifurcation order?

12     A.     Program costs and shareholder incentives that are currently recovered through  
13     the DSM component of the IRP Clause for the energy efficiency and load  
14     management DSM programs will continue to be recovered through the IRP  
15     Clause until new programs are approved and a new mechanism is in place to  
16     recover DSM-related costs, and costs that currently have to be recovered through  
17     base rates related to such programs will be included in base rates.

18     Q.     What about lost margins?

19     A.     At present, lost margins incurred as a result of implementing energy efficiency  
20     DSM programs are recovered through the DSM component of the rate IRP  
21     Clause between rate cases. In rate cases, the impact of DSM programs on test  
22     year sales can be directly taken into account. Only future lost margins will be  
23     recovered through the IRP Clause after new rates are set.

24     Q.     Why is there a difference between the rate increase proposed in HECO's

25             Application and that justified in its Rebuttal Testimonies?

1       A.     As stated above, an estimated \$29 million related to the existing and enhanced  
2             DSM programs, have been removed from the rate increase request due to result  
3             of Order 21698. The DSM portion of the IRP Clause revenues has been reduced  
4             to reflect only the lost margin portion of the DSM programs currently being  
5             recovered through the IRP surcharge. See Mr. Alan Hee's rebuttal testimony  
6             (HECO RT-10) for a discussion on the calculation of the IRP Clause revenues.

7             As a result of the removal of DSM program costs, HECO anticipates  
8             slightly higher estimated sales due to lower DSM program impacts. There were  
9             also changes in certain operations and maintenance expenses and rate base  
10            components for the 2005 test year based on updated information and actual  
11            year-end 2004 balances, and lower rates of return on common equity and rate  
12            base of 11% and 8.83%, respectively. In addition, HECO has agreed to lease  
13            nine 1.64 MW distributed generating units, to be installed at three HECO  
14            substation sites (to help address the reserve capacity shortfall situation), and has  
15            proposed that the annual lease costs totaling about \$1.5 million be included in  
16            test year O&M expenses. All of the changes are addressed by our rebuttal  
17            witnesses.

18       Implementation of Rate Increase

19       O.\_\_\_\_ How is HECO requesting that the increase be granted?

20       A.     There has been no change in HECO's implementation of its proposed rate  
21             increase from what the Company set forth in its application. HECO requests that  
22             the general increase and revisions to its rate schedules be granted in two steps:

1           Section 269-16(d). HECO will determine the amount that it is requesting as  
2           an interim increase at the close of evidentiary hearing, based on the  
3           evidence before the Commission.

4           2) A Final Increase when the Commission issues its final decision and order to  
5           provide for the amount of the total requested revenue increase not included  
6           in the Interim Rate Increase.

7       Q.    When does HECO propose that the Commission grant its proposed increase?

8       A.    HECO proposes that the Commission issue an order granting an Interim Rate  
9           Increase as soon as practicable after the evidentiary hearing is held in this  
10          proceeding. The evidentiary hearing is expected to be completed in September,  
11          2005. However, HECO's rebuttal Results of Operations demonstrate that HECO  
12          had a need for a rate increase at the beginning of 2005. Thus, HECO requests  
13          that an interim order be issued as soon as practicable.

14      Q.    How does HECO propose to implement the proposed rate increase?

15      A.    HECO proposes to implement the final increase with the proposed rates and  
16          charges that are reflected in HECO-R-2224, or with such other rates and charges  
17          as approved by the Commission. The Interim Rate Increase implemented prior  
18          to the final step would be structured as surcharges to the various classes based on  
19          a percentage of the customer's bill (exclusive of Energy Cost Adjustment  
20          charges and other surcharges). The allocation to each rate schedule will be  
21          consistent with the likely final rate increase allocation. Mr. Young discusses the  
22          allocation of the proposed increase to each rate schedule in HECO RT-22. The  
23          allocation of the proposed increase to each rate schedule is shown in  
24          HECO-R-2204.

25      Q.    Is this proposed implementation of the requested step increase consistent with

1 past practices with the Commission?

2 A. Yes. This implementation method was used for recent interim increases in  
3 HECO's last rate case, Docket No. 7766 and in HELCO's last rate case, Docket  
4 No. 99-0207.

5 Revenue Increase Allocation

6 Q. What was HECO's proposal with respect to allocation of its requested revenue  
7 increase to the various rate schedules in its Application?

8 A. HECO proposed to allocate its requested revenue increase as an equal percentage  
9 increase to each rate schedule. HECO's proposal departed from past revenue  
10 increase allocations. HECO T-22, pages 17-18, lines 24-1.

11 Q. Has HECO revised its proposal?

12 A. Yes. As set forth in Mr. Young's rebuttal testimony (RT-22), HECO plans on  
13 allocating the revenue increase to rate schedules, such that the rates will move  
14 closer to the cost to serve that particular rate class, as reflected by each class's  
15 rate of return moving closer to the system average rate of return.

16 Q. Has this revised proposal been applied by HECO in prior cases?

17 A. Yes. HECO has applied these guidelines in HECO's last rate case, Docket No.  
18 7700 and HELCO's last rate case, Docket No. 99-0207, and has been accepted  
19 by the CA and DOD as well as approved and found reasonable by the  
20 Commission.

21 Q. What is the reason for revising its proposal?

22 ~~A. In HECO's direct testimony, the Commission stated that if the amount of HECO's~~

1 page 28, lines 15-19. Since HECO's proposed revenue rate increase is  
2 significantly lower than the proposed increase set forth in HECO's direct  
3 testimony, it is reasonable for HECO to return to a proposed revenue increase  
4 allocation that more closely aligns class revenues and class costs. A discussion  
5 of HECO's revisions to its revenue increase allocation is addressed in Mr. Peter  
6 Young's rebuttal testimony (HECO RT-22).

7  
8 MAJOR ISSUES

9 Q. What is the CA proposing in this proceeding?

10 A. The CA is proposing that HECO's rates increase by \$23.5 million. Thus, there is  
11 a \$ 39.5 million difference between HECO and the CA with respect to HECO's  
12 test year revenue requirements.

13 Source

14 HECO \$ 63.0 million HECO-R-2301, (HECO's  
15 Rebuttal at present rates)

16 CA - \$ 23.5 million Exhibit CA-101, Schedule A  
17 difference \$39.5 million

18 (In its response to information requests, however, the CA has indicated that some  
19 of its test year estimates should be revised or corrected, and that it would do so  
20 "upon completion of all required updates and revisions to CA Exhibit 101." For  
21 example, see Responses to HECO/CA-IR-104.c., HECO/CA-IR-120,  
22 HECO/CA-IR-122, HECO/CA-IR-202, HECO/CA-IR-209.) The differences  
23 between the CA and HECO are fully addressed by HECO's witnesses in their  
24 rebuttal testimonies.

25 Q. What is the DOD proposing in this proceeding?

A. The DOD is proposing that HECO's rates be increased by \$19.3 million. See Exhibit DOD-101, page 1. Thus, there is a \$ 43.7 million difference between HECO's rebuttal position at present rates and DOD with respect to HECO's test year revenue requirements.

Source

HECO	\$ 63.0 million	HECO-R-2301
DOD	- <u>\$ 19.3 million</u>	Exhibit DOD-101
difference	\$ 43.7 million	

The differences between the DOD and HECO also are fully addressed by HECO's witnesses in their rebuttal testimonies.

Q. What are the major issues remaining between HECO and the CA and the DOD will you address in your testimony?

A. I will briefly address the following major issues:

- 1) Return on Equity,
- 2) Prepaid Pension Asset,
- 3) Employee Count, and
- 4) Annualization of Certain Test Year Costs

Return on Equity

Q. What is HECO's proposed return on common equity?

A. HECO's proposed return on common equity is 11.0%.

Q. What is the CA's proposal on HECO's return on common equity?

A. The CA provides a range on its proposed return on common equity of 8.5% to 10%, with a mid-point of 9.25%. CA-T-4, page 4, lines 17-18.

Q. What is the DOD's proposal on HECO's return on common equity?

A. The DOD recommends a common equity return allowance of only 9.00%, which

1 is in the lower portion of a range of 8.75% to 9.50%. DOD T-2, page 2, lines  
2 17-20.

3 Q. Why is HECO's proposed return on equity needed?

4 A. The return on equity must not only meet the standards set forth in the Bluefield  
5 and Hope cases, it must be sufficient to assure investor confidence in the  
6 financial integrity of HECO. This will enable the Company to maintain its credit  
7 and capital-attracting ability. Financial integrity and financial strength are  
8 important considerations in determining a fair rate of return on rate base and on  
9 common equity for the Company.

11 A. Financial integrity is important for both the Company and its ratepayers. If  
12 HECO's financial integrity is protected, the Company should be able to attract  
13 capital on reasonable terms that it needs to provide service to its customers, and  
14 should be able to attract capital under whatever economic conditions might exist  
15 at the time HECO needs to raise capital. HECO's customers can also count on  
16 the Company providing reliable electric service in the future. HECO and its  
17 customers will ultimately benefit from this.

18 Q. Why must financial strength also be considered?

1 determining a fair rate of return on common equity, it is appropriate to consider  
2 the economic conditions that will prevail during the period that rates set in the  
3 rate case are in effect. It is also important to recognize that electric rates will be  
4 in effect for more than a few months, and to take a somewhat longer range view  
5 in arriving at a fair rate of return for the Company. The need for a longer range  
6 view was acknowledged by the Commission in a prior HECO rate case, Docket  
7 No. 3705, Decision and Order No. 6275 (July 9, 1980) where the Commission  
8 decided not to establish a high rate of return on equity that would have been  
9 commensurate with the high interest rates and high dividend yields that the  
10 market was experiencing at the time. The Commission should apply its policy  
11 on this matter consistently, and not place undue emphasis on current market  
12 conditions when interest rates are lower. In setting the rate of return on common  
13 equity, the Commission should base its determination on a return that allows the  
14 Company stability in its rates. It will then allow HECO to better plan its  
15 financial affairs if the return on equity is not highly variable from rate case  
16 decision to rate case decision.

17 Q. What impact does HECO's allowed rate of return on common equity have on  
18 rating agencies and the investing public?

19 A. HECO's allowed rate of return will have a tremendous impact on rating agencies  
20 and the investing public. It indicates to them whether or not the Company's  
21 regulators continue to acknowledge the risks with which HECO must deal. It  
22 adds confidence to the regulatory process when the investment community  
23 perceives that there is reasonable stability with respect to the rate of return.

24 Given the risks that HECO faces, it is especially important that the Company be  
25 afforded the opportunity to earn an appropriate return on common equity, which

1 is 11.0%. Mr. Roger Morin, Mr. Richard von Gnechten, and Ms. Tayne  
2 Sekimura, further address Rate of Return on Common Equity, Cost of Capital  
3 and HECO's business and investment risks in HECO RT-20, HECO RT-21 and  
4 HECO RT-16, respectively.

5 Prepaid Pension Asset

6 Q. What is the prepaid pension asset?

7 A. The prepaid pension asset is the net of the cumulative contributions the  
8 Company has made to the pension fund for its employees less the recognized  
9 pension liability (i.e., the accumulated net periodic pension cost or NPPC).

10 Q. Please summarize why should the Commission allow the prepaid pension asset  
11 in HECO's rate base?

12 A. As Ms. Tayne Sekimura discusses in her rebuttal testimony, HECO RT-16, there  
13 are a number of reasons. First, this ratemaking treatment would be consistent  
14 with the ratemaking treatment that has consistently been used for pension costs.  
15 Pension costs have consistently been determined under the guidance in  
16 Statement of Financial Accounting Standards No. 87 ("SFAS 87"). Recognition  
17 of the prepaid pension asset results from the consistent and proper application of  
18 SFAS 87. Second, it reflects an investment that the Company has made in the  
19 pension plan. Investors have provided the funds for contribution to the pension  
20 plan just as investors provide funds for any of the Company's investments. The  
21 pension plan is an integral part of the Company's compensation to its employees  
22 and is one of the elements necessary to attract and retain quality employees that  
23 are engaged in the provision of electric service to the public. Third, the prepaid  
24 pension asset accrues definite benefits to the ratepayer. Generation of the  
25 prepaid pension asset has resulted in a lower NPPC, enabled the Company to

1           avoid negative tax consequences and has a positive impact on the Company's  
2           credit quality.

3       Q.    What are the positions of the CA and the DOD on this issue?

4       A.    The CA and the DOD recommend the complete removal of the prepaid pension  
5           asset from rate base. However, their arguments are flawed and constitute  
6           retroactive ratemaking. By disallowing the prepaid pension asset from rate base,  
7           they seek to make up for what they perceive to be an over recovery of NPPC in  
8           the ten years between this and the Company's last rate case. Neither the CA nor  
9           the DOD question the validity or value of the asset, they simply take the position  
10          that ratepayers have funded the investment. Because this disallowance would  
11          reduce revenue requirement and ultimately decrease the Company's rates, it  
12          would in effect pay money back to ratepayers for this alleged over-recovery.  
13          This is clearly retroactive ratemaking and should be rejected by the Commission.  
14          The CA acknowledges that each element of the Company's revenue requirement  
15          can be expected to vary through time. And it is a fact that while the NPPC has  
16          generally decreased since the last rate case, there are other expenses that have  
17          substantially increased. For the purposes of this rate case, attention should be  
18          focused on the levels of all of the Company's expenses and investments in the  
19          test year rather than on whether there has been over or under-recovery of a

20               single item in the past.

21       Employee Count

22       Q.    The CA contends that HECO's proposed average employee level should be  
23           reduced (CA-T-2, pages 76-81) for the purposes of determining the Company's  
24           revenue requirements. From an overall policy standpoint, please explain why

1       A.     In 2001, prior to the events of September 11, HECO's financial projects for 2002  
2             and 2003 indicated that earnings would be below the last allowed return. The  
3             events of September 11, 2001, created substantial economic uncertainty for our  
4             nation, our state and HECO. Kilowatthour sales dropped 3% after the terrorist  
5             attacks, and the impact of the fall in the stock market on HECO's pension plans  
6             was very dramatic. At that point, HECO appeared to be in a dire situation and  
7             was looking at the potential for furloughs, layoffs of a substantial number of  
8             employees, and significant benefit cuts and eliminations. Before taking such  
9             drastic measures, HECO implemented staff caps, and staffing levels were  
10            carefully monitored. A few examples of Company initiated temporary cost  
11            reduction efforts included restrictions in mainland travel and training, office  
12            supplies, construction of new facilities, renovations, or relocations other than  
13            "box" moves, and hiring. Vacancies were not automatically filled. Each position  
14            had to be justified in light of current circumstances and, whenever the  
15            opportunity presented itself, HECO managed with less than was necessary in the  
16            long term. Rather than pursue drastic measures, HECO consciously decided to  
17            simply weather the economic turmoil of the terrorist attacks. Filing a rate  
18            increase application at such a time would have significantly impacted the already  
19            soft economy in Hawaii. HECO deliberately reduced spending, while not  
20            compromising reliability, during that period. This was possible largely through  
21            the efforts of our employees who picked up the slack in areas that were unfilled.  
22            However, such reduction in the level of spending and holding unfilled positions  
23            vacant cannot continue for an indefinite period of time. Vacancies need to be  
24            filled to ensure proper working conditions for our existing employees and  
25            operational viability in the long term. As more fully described by many of the

1 witnesses in their rebuttal testimonies, the test year levels for the respective  
2 employee count may be higher than recent historic levels because of the financial  
3 constraints that were imposed after the events of September 11.

4 For example, the age of our generating units and associated infrastructure  
5 have increased the Company's actual Other Production O&M expenses over the  
6 years since our last rate case. The trend shows a general and significant increase  
7 due to the aging phenomena over most years from 1995-2002 when the system  
8 had adequate capacity reserves due to lower demand than was experienced in  
9 2003 and 2004, and is anticipated in 2005 and beyond. The combination of these  
10 factors are driving the need to increase Other Production O&M including aging  
11 units that require more maintenance as the are being operated "harder" to meet  
12 the demand; reduced maintenance flexibility; empirical evidence of rapidly  
13 growing demand into the foreseeable future; and the need to increase staffing as  
14 part of an overall mitigation plan to maintain availability and the reliability of  
15 existing HECO generating units. These expenses, among others, will continue to  
16 be incurred until we are able to add new generation to help address the reserve  
17 capacity shortfall situation. (See HECO's responses to CA-IR-35, CA-IR-37,  
18 and CA-IR-170).

19 Q. What information has HECO provided to justify its proposed employee count for  
20 the test year?

21 A. Ms. Tayne Sekimura's rebuttal testimony (RT-16) addresses this issue from a  
22 Company-wide perspective, and extensive direct and rebuttal testimonies and  
23 responses to information requests have been provided by our O&M witnesses,  
24 who have first-hand experience with this need for additional staffing. In  
25 summary, HECO provided a significant amount of information concerning its

1 “optimal staffing level” in its direct and rebuttal testimonies, and responded to  
2 numerous specific information requests regarding its existing staffing levels, how  
3 HECO determined its optimal staffing levels, and what work would not get done  
4 with less than optimal staffing. (HECO’s responses to CA-IR-630, CA-IR-20,  
5 CA-IR-21, CA-IR-1 (7 volumes), CA-IR-48.a, -176.a, -482, 483 and -486.c,  
6 CA-IR-269, CA-IR-9, -48.f, -71, -298, -508, -509, -510.b, -600, -601, -602,  
7 -657, CA-IR-48.g, -59.b., c., -60.a, -61.a, -62.a, -70.b, -77.a, -173, -174, and -175  
8 are a few examples.)

9 Q. The CA contends that the Company’s assumptions are not realistic,  
10 “[p]articularly true when a company is in the process of transitioning from a  
11 self-imposed austerity program that constrained the hiring of employees to a  
12 more robust staffing environment.” CA-T-2, page 78, lines 12-14. What is the  
13 Company’s response?

14 A. As the Company is mindful of producing and delivering a reliable supply of  
15 electricity when and where our customers need it, in a safe manner, and at  
16 reasonable prices, the Company continually strives to achieve improvements in  
17 efficiency and productivity and reflects them in our budgeted work force

18 requirements and non-labor costs. As such, the Company does not believe that

1 Q. What is the stated basis for the CA's approach?

2 A. The CA bases its approach on the use of an "average" test year. However, for  
3 purposes of this rate case, there are at least three fundamental problems with the  
4 CA's approach, as Ms. Sekimura addresses in HECO RT-16. First, much of the  
5 staffing increase is for new positions, and is not just to fill previously authorized

1           been a "lag" in filling some of the new positions, and even though there have  
2           been some vacancies in existing positions.

3           Annualization of Certain Test Year Costs

4           Q.     For certain expenses, HECO is proposing to annualize the level of those  
5           expenses. What does "annualize" mean in this context?

6           A.     "Annualize" means to make an adjustment to reflect what the normal ongoing  
7           level of expenses would be in the test year if the associated activity were  
8           performed for the entire year. Annualization would typically be performed on  
9           expenses for new or expanded activities that would begin at some point after the  
10          beginning of the test year but are expected to continue on a permanent basis  
11          going forward. Two examples in HECO's rate case are the distributed  
12          generation ("DG") units to be installed in the late third and early fourth quarters  
13          of 2005 and the filling of newly created positions, which is occurring over the  
14          course of 2005. These are "known and measurable" changes in the way in which  
15          HECO serves its customers, and the activities and associated expenses will  
16          continue on into the future and we have definitive information on what the  
17          associated expenses will be. Annualizing these expenses ensures that when the  
18          new rates resulting from this rate case go into effect, there will be adequate

1 would not be able to maintain the Company's financial integrity. Ms. Tayne  
2 Sekimura addresses this issue in her rebuttal testimony (HECO RT-16).

3 Q. What is the Consumer Advocate's position on annualization?

4 A. The CA objects to it. It contends that because the test year in this case is based  
5 on an average, as opposed to year-end, rate base, average sales levels and for the  
6 most part average expenses, "HECO should not be allowed to select specific  
7 costs that are known to be increasing and annualize them at year-end, while not  
8 moving the rest of the ratemaking elements to a matched, year-end point in  
9 time." The CA appears to equate annualization with utilizing year-end financials  
10 and argues that annualization is inconsistent with the average approach used for  
11 this rate case. It alleges that it is important for revenues, rate base and expenses  
12 to be measured as of a common point or period of time so that the relationship  
13 between revenues and costs is not mismatched (CA-T-1, pages 12-13).

14 Q. Is the annualization of expenses for the items that you previously identified  
15 consistent with the test year sales and expenses?

16 A. Yes, it is. The test year sales and expenses are intended to represent normal  
17 operations in the test year and they must be at a level that will result in a revenue  
18 award and ultimately rates that will provide the Company with the opportunity to  
19 earn the authorized rate of return when the award goes into effect. As I  
20 mentioned earlier, the O&M expenses associated with the new DG units and the  
21 labor expenses associated with new positions that will be filled are not an  
22 anomaly. They will continue on and will be part of the Company's normal  
23 operational expenses. As a result, the impact of these "known and measurable"  
24 changes should be annualized so that a full year of those expenses will be  
25 captured in revenue requirements. If they are not annualized, as the CA

1 recommends, they will be understated and the relationship between revenues and  
2 costs (as the CA talks about on page 10 of its testimony) will be distorted,  
3 resulting in rates that are too low and do not afford the Company the opportunity  
4 to earn its authorized rate of return.

5 In addition, new rates are not being set at the beginning of 2005. If rates  
6 were reset at the beginning of the year, and it was assumed that new positions  
7 were filled and new DG units were leased as of the beginning of the year even  
8 though new positions are filled over the course of the year and the new units are  
9 not installed until the third and fourth quarter, then the amount included for  
10 staffing and new DG units in rates for 2005 (looked at in isolation) might be too  
11 high. In this case, however, rates are not expected to be reset until at least  
12 October 2005 (for the interim increase) and until next year (for the final  
13 increase).

14 Q. Are any "annualization adjustments" made as a matter of course in calculating  
15 the amount of the needed rate increase?

16 A. Yes. Although the CA appears to argue that any annualization adjustment would  
17 "violate" the average test year concept, some major annualization adjustments  
18 are made as a matter of course that decrease the amount of the approved rate  
19 increase. For example, the "assumption" is made that the approved rate increase  
20 will be in effect for the full test year, even though in this case the interim  
21 increase is expected to be in effect only in the fourth quarter of 2005. To obtain  
22 the full increase in 2005, when it will be in effect for only one-quarter, the actual  
23 increase would have to be 4 times the authorized increase. Obviously, that  
24 would be unfair to ratepayers in the period after 2005 when the increase would  
25 continue to be in effect. Thus, the increase is "normalized", by annualizing the

1 effect of the increase

2 The assumed annualization of the impact of the rate increase also serves to  
3 substantially reduce the working cash included in rate base. HECO's estimated  
4 working cash is reduced from \$10,107,000 at present rates to \$1,648,000 at  
5 proposed rates (because income taxes and revenue taxes are higher at proposed  
6 rates, and payments by receipt of revenues for these items).

7 The Commission also has consistently recognized the need to annualize the  
8 effect of a new or modified power purchase agreement ("PPA") and has  
9 annualized the impact even when an average test year is used. In this case, both  
10 the CA and DOD have included the annualized impacts of the amendments to the  
11 PPA with Kalaeloa Partners, L.P., although the contract modifications will not be  
12 effective until the interim increase becomes effective.

13 Q. Please respond to the CA's claim that normalization is acceptable for application  
14 in a rate case, but annualization is not (CA-T-1, pages 17-18).

15 A. I disagree. Annualization, when properly applied, is a form of normalization.  
16 Both seek to adjust expense or revenue amounts to normal, ongoing levels.  
17 Normalization usually involves smoothing out expense or revenue items that  
18 look unusually high or low. In terms of the purpose of normalization, the CA  
19 states: "If not normalized, inclusion of excessively high or low test period costs  
20 would create an over or under-recovery of such costs in future periods when  
21 more normal cost levels are expected to be incurred." (CA-T-1, page 17, lines  
22 11-14). What the CA is saying is normalization should have the effect of  
23 reflecting more normal cost levels in future periods. However, what this means

1 normal levels are expected to be incurred), which is the CA's basis for rejecting  
2 the use of annualization in a rate case (CA-T-1, page 18, lines 5-8).

3 I would also point out that a normalizing adjustment is often based on  
4 historical data. In so doing, the normalization has again transformed the point in  
5 time when the test year measurement is performed (i.e., to some period in the  
6 past as opposed to the time period upon which the test year is based.)

7 Thus, if normalization is acceptable even when the time period upon which  
8 the normalization is based is different from the test year, the CA should not  
9 object to the use of annualization. Normalization, as applied by the CA, usually  
10 results in a reduction of an expense level. Annualization usually involves an  
11 increase in an expense level to reflect a full year of ongoing costs. They both  
12 seek to adjust test year expense to reflect normal, on-going levels. Hence, if  
13 normalization is allowed, there is no reason to reject annualization out of hand.  
14 If it is, the test year revenue requirements will be skewed, further understating  
15 the Company's costs.

16 Q. Please respond to the CA's contention that it is not necessary to annualize costs  
17 for full recovery to be possible because growth in revenues may be more than  
18 sufficient to offset these costs in the future (CA-T-1, page 16, lines 1-18).

19 A. The CA has provided no support for this contention. It is also contrary to the  
20 CA's principle that relationships between revenues and costs need to be captured  
21 in a balanced way such that future growth trends in revenues and costs are  
22 offsetting (CA-T-1, page 10, lines 5-14). If annualization is not allowed, even  
23 though there is knowledge that those expenses will be ongoing, revenues  
24 (resulting from a deficient rate award) will be too low in future years putting the  
25 relationship between revenues and costs out of balance.

1 Q. Using specific examples, please explain why the CA's contention is misguided.

2 A. The CA erroneously assumes that the Company's sales will offset any rate base  
3 growth, which is simply not the case. For example, the CA made a proposed  
4 adjustment to the O&M expenses on the DG units, including only expenses for  
5 the months the DG units were expected to be operational in 2005. (CA-T-1,  
6 pages 31-32, lines 21-4 and CA Exhibit-101, Schedule C-7.) The CA alleges  
7 that the new revenues from continuing load growth will be sufficient to offset the  
8 full annual costs of the DG and even suggests that revenue growth may be able  
9 to cover for additional DG installation in 2006 and beyond. (CA-T-1, page 32,  
10 lines 10-18.) As discussed by Mr. Seu in HECO RT-7, the CA's proposed  
11 expense will only amount to about one-quarter of the annualized expense that  
12 will be incurred for the nine DG units that will be placed in service in the test  
13 year, a small fraction of the actual expenses that will be incurred by HECO from  
14 the date that new rates would take effect. The gap between the CA's proposed  
15 amount and the actual costs that will be incurred by HECO is simply too large to  
16 rely on a hope that sales revenues will grow and that utility costs in other areas  
17 will not increase. (See Ms. Hazama's Rebuttal Testimony (HECO RT-2) on  
18 Sales.) The DG units are intended to be operated only intermittently when  
19 generating capacity reserves are low or system support is needed. Revenues  
20 associated with the energy generated from these DG units will in no way pay for  
21 the expenses that will be incurred to have the units available to serve HECO's  
22 customers. Adding the DG units will result in new, additional operational  
23 expenses that will be incurred in HECO's operations, and there will be no  
24 corresponding expense reductions in other areas. After the units are leased,  
25 HECO will be incurring at least the level of annualized costs to provide this

1 critical DG service to its customers, and it is likely that higher costs will be  
2 incurred in 2006 and beyond.

3 Q. If annualization is allowed, would the test year revenues need to be  
4 correspondingly increased?

5 A. For the expenses that the Company seeks to annualize, the answer would be no.  
6 I say this for two reasons. First, there would need to be a causal relationship  
7 such that the activity associated with the expense would cause sales to increase.  
8 This causal relationship does not exist for the new positions that will be filled,  
9 nor does it exist for the installation of the DG units. The purpose of the DG units  
10 is to mitigate the Company's' reserve capacity shortfall and the likelihood of  
11 system outages, not to increase sales. The DG units will be operated on a limited  
12 basis in circumstances where the other, larger generating units available to  
13 HECO cannot support customer load. Technically, if the DG units were not  
14 available to prevent an outage and an outage occurred, then sales would be lower  
15 compared to the scenario with DG. However, it is clear that the installation of  
16 the DG units in and of itself does not cause sales to increase.

17 Second, the Company's sales forecast in this rate case is not dependent on  
18 generating capacity or labor expense levels. As explained by Ms. Catherine  
19 Hazama throughout her direct testimony, HECO T-2, the sales forecast was  
20 dependent almost exclusively on external market demand factors. Thus, there is  
21 no capacity constraint assumed in the test year sales forecast. It assumes that the  
22 Company will be able to provide the capacity it needs to meet demand levels. As  
23 a result, even if there are incremental revenues associated with the new DG units,  
24 they are already built into the existing test year sales forecast and there would be  
25 no need to adjust the test year revenues.

1 OTHER POLICY MATTERS

2 Q. What are other policy matters will you be covering in this section?

3 A. My rebuttal testimony will address the following policy issues:

- 4 1) Ratemaking Treatment of Financial Constraints,
- 5 2) Test Year Results of Operations vs. the 2005 Operating Budget,
- 6 3) Amortization of Rate Case Expense,
- 7 4) CA Proposed Recommendations for Potential Reserve Adjustment
- 8 Mechanisms,
- 9 5) Reserve Capacity Shortfall,
- 10 6) New Company Initiatives,
- 11 7) Underground Cost-Sharing Policy, and
- 12 8) The need for an Energy Cost Adjustment Clause,

13 Ratemaking Treatment of Financial Constraints

14 Q. What policy consideration is presented with respect to the ratemaking treatment  
15 of financial constraints?

16 A. From a ratemaking policy standpoint, the Company seeks to include test year  
17 operating and maintenance expenses at a "normal" level. However, from a  
18 financial policy standpoint, the Company seeks to maintain our financial

---

---

---

1 expected to be lower than acceptable, which is the reason for the rate increase  
2 request. From the financial standpoint, there is a need to improve the "bottom  
3 line" relative to what it would be if the Company continued incurring costs on a  
4 normal basis. The solution to this dilemma from the financial policy standpoint  
5 is to impose financial constraints on the Company's operation.

6 Q. From a ratemaking policy viewpoint, if the Company has not incurred the  
7 expenses in the past at the levels now proposed, in part due to financial  
8 constraints, why should the Company's rates set in this rate case include these

9 costs?

10 A. From a ratemaking policy viewpoint, the rates should be representative of the  
11 future period when rates will be in effect. Even if the Company has not incurred  
12 expenses at the same levels in prior years, if the expenses are known and  
13 measurable, they should be included for ratemaking purposes during the period  
14 when the rates are in effect. If they are not, there will be a short fall in recovery  
15 and the Company will not have the opportunity to earn a fair rate of return on its  
16 investments from the first day the new rates are in effect.

17 Post 911 Era

18 Q. As a result of the events of 911, the Company attempted to strike a delicate  
19 balance by deliberately reducing spending without compromising safe and reliable

1 expenses are driven by the work required by the various process areas to operate  
2 and maintain power plants, to negotiate and administer power purchase  
3 agreements, to operate and maintain the transmission and distribution systems, to  
4 meter and bill customers and respond to their service inquiries, to provide energy  
5 services to customers, to help customers use electricity more wisely and  
6 efficiently, to comply with accounting, financial disclosure, environmental,  
7 regulatory and legal requirements, to address community concerns, to acquire the  
8 capital required to finance the utility's facilities and equipment, and to manage  
9 and supervise the utility's employees and contractors. In HECO's rebuttal  
10 testimonies, employees involved in managing and supervising the activities in  
11 the various process areas, explain in detail, the reasons for the expenses, and the  
12 bases for the expense levels.

13 Q. How do you determine what is reasonable?

14 A. Judgment may be required by employees as they prepare their budget, and  
15 therefore the test year expense projections, and in determining if expense  
16 estimates being proposed are "reasonable." For example, judgment may be used  
17 when determining whether to use historical costs or a specific proposal for a  
18 similar type of cost item as the basis for developing the budget amount.

19 Q. Is it practical to "[s]tate with specificity each of the objective criteria or tests that  
20 were applied by HECO to determine if the expenses that have been included in  
21 the 2005 test year projections are 'reasonable'", as the CA requested in  
22 CA-IR-268(a)?

23 A. It is not practical to attempt to list all of the "criteria" considered in determining  
24 what needs to be done to provide, safe, reliable adequate electric service, and to  
25 comply with all applicable requirements, and to then show a quantified (such as

1 by deriving a mathematical model), direct linkage between the criteria and the  
2 level of the expense. For example, HECO has capacity planning criteria and  
3 considerations (i.e., LOLP). Achievement of the LOLP consideration is  
4 dependent on things like reserve margin and unit EFORs, which in turn depend  
5 on how well the units are operated and maintained, which in turn depend on the  
6 resources available to operate and maintain the units (hence the judgment that the  
7 Production Department needs to add operators to staff Honolulu 8 & 9 and  
8 Waiau 3 & 4 on a 24/7 basis instead of a 16/7 basis, and to add night  
9 maintenance shift crews at Kahe and Waiau). In operating and maintaining  
10 units, HECO applies practices based on Company practice manuals, industry  
11 practice, manufacturer recommendations, environmental laws and permits, PUC  
12 rules (e.g., to meet frequency and voltage requirements), and insurance  
13 inspection requirements. Judgment is based on the expertise of in-house experts,  
14 and outside sources (such as manufacturers, EPRI, other consultants), where that  
15 expertise is obtained through education and experience.

16 Q. The CA questions whether the Commission should expect the Company to  
17 maintain any continuing budget austerity plans, ongoing hiring constraints or any  
18 other spending limitations in an effort to promote operational efficiency and  
19 minimize the burden of rate increases upon customers. Could you please  
20 respond.

21 A. As the Company is mindful of producing and delivering a reliable supply of  
22 electricity when and where our customers need it, in a safe manner, and at  
23 reasonable prices, the Company continually strives to achieve improvements in  
24 efficiency and productivity and reflects them in our budgeted work force  
25 requirements and non-labor costs. As such, the Company does not believe that

1 the Commission should expect the Company to maintain any continuing budget  
2 austerity plans, ongoing hiring constraints or any other spending limitations in an  
3 effort to promote operational efficiency and minimize the burden of rate  
4 increases upon customers. The Company, however, may institute budget  
5 austerity plans, hiring constraints, and other spending limitations in times of  
6 economic uncertainty, while not compromising reliability and safety, and in an  
7 effort to maintain financial integrity. (See HECO's response to CA-IR-269.)

8 Test Year Results of Operations vs. the 2005 Operating Budget

9 Q. Are there differences between the normalized results of operations for the test  
10 year presented in direct testimony and the operating budget for 2005?

11 A. Yes. The biggest difference is that the test year results of operations at  
12 proposed rates "assume" that the rate increase determined to be needed goes into  
13 effect at the beginning of the test year. Based on the regulatory requirements for  
14 an interim order (as addressed later in my testimony), the operating budget  
15 assumes interim relief in the fourth quarter, and does not assume a final rate  
16 order in 2005. In addition, as explained in the direct testimonies and in HECO's  
17 response to CA-IR-14, there are differences between the test year estimated  
18 expenses and the operating budget for 2005.

19 The starting point for the 2005 O&M expense estimates that were filed with  
20 the PUC for rate case purposes was the 2005 annual budget that was initially  
21 developed in 2003 and reviewed and revised in early 2004. As addressed in  
22 HECO T-1, pages 24-27, HECO T-13, pages 3-5, and HECO T-18, pages 15-17,  
23 the following types of adjustments generally were then made to that revised  
24 2005 budget to arrive at the 2005 test year estimates: (1) To simplify and limit  
25 issues in this proceeding, certain expenses such as non-qualified pension

1 expenses, incentive compensation for employees and executives, 401(k)  
2 administration expenses, the expenses related to annual service awards and  
3 Executive Life Insurance were eliminated; (2) Adjustments were made to the  
4 O&M budget for ratemaking purposes to better represent “normal” ongoing  
5 Company operations for the period during which the proposed rates will be in  
6 effect; and (3) DSM utility incentives were included in O&M expenses for the  
7 direct revenue requirements calculation (but have now been removed as  
8 explained earlier).

9 Certain adjustments were made to that revised 2005 budget, after it was  
10 “frozen” for the development of the test year estimates, including: (1) Updating  
11 preliminary pension estimates; (2) Adding Broadband over Power Lines (BPL)  
12 expenses, for which the Company is not currently seeking cost recovery; and (3)  
13 Adjusting for then known changes such as additional staffing of \$1,930,000 (less  
14 \$490,000 representing the lag in the hiring process for the additional staffing, for  
15 a net addition of \$1,440,000), and higher lease rent expense of \$430,000 for  
16 office space in the Pauahi Tower, offset by a reduction of \$3,694,000 for  
17 consideration of a lag in the hiring process for positions included in the updated  
18 2005 budget (even with the lag, the 2005 year-end employee count is still  
19 assumed to be attained). As part of the process, other non-labor expense  
20 increases, in addition to the rent increase, totaling \$1,923,900 were identified  
21 and allowed to be spent, but it was assumed other unspecified non-labor  
22 expenses in the budget would be reduced, so that there was no net increase to the  
23 budget for these items.

24 Management also was concerned that revenues would not be able to support  
25 the level of spending in the budget because rate relief was expected to begin no

1 earlier than in the fourth quarter of 2005. An unspecified target reduction of  
2 \$1,193,000 was made to reflect an assumed reduction in spending in the short  
3 run. The target reduction was allocated to the process areas (and some process  
4 areas further allocated their target adjustments to their departments) based on  
5 each process area's O&M budget adjusted for specific items such as the hiring  
6 lag. Each process area was given discretion as to how to achieve the reduction,  
7 as long as safety, reliability and service were not put at risk.

8 Q. Please describe how an adjustment was made for the hiring lag in its budget.

9 A. The adjustment for hiring lag started with a projected 2004 year-end employee  
10 count and assumed that positions would be filled evenly throughout 2005 to get  
11 to the year-end budgeted employee count. Since the budget reflected most  
12 positions being filled at the beginning of the year, the difference in monthly  
13 employee count resulted in lower costs and is referred to as the "hiring lag  
14 adjustment".

15 Q. Please explain what "target adjustment" means.

16 A. While referred to as a "target adjustment", the "target" does not represent a  
17 mandatory reduction in spending, and the Company recognizes that it may not be  
18 achieved, as the Company will do what needs to be done to provide safe and  
19 reliable service. For example, once a generating unit is opened and the overhaul  
20 is fully underway, it is possible that the length and costs of the overhaul will be  
21 longer and higher than originally budgeted. As a result of a longer than expected  
22 outage for Waiau 9 at the end of 2004 and extending into 2005, HECO Power  
23 Supply has had to adjust the overhaul schedule 2005, resulting in higher  
24 overhaul expenses in 2005 than were budgeted (or included in the test year  
25 estimates). This is addressed in HECO RT-6 and HECO's response to CA-IR-

1           242. As indicated in the response, the budget and "target" for the Production  
2           O&M Department are \$57,000,920 and \$54,655,000, respectively. However,  
3           despite its target, as of April 1, 2005, the Production O&M Department projected  
4           spending even more than the \$57 million budget amount, primarily due to the  
5           revised generating unit overhaul schedule.

6           Q.    Are there differences between the operating budget and expected actual results  
7           of operations in 2005?

8           A.    Yes. As explained in HECO RT-2, sales are now expected to be lower in 2005  
9           by approximately 13.2 GWH, which would result in a loss of about \$754,000 in  
10          revenues net of fuel and purchased power expenses to generate the lost GWH.  
11          As addressed in HECO RT-6, production maintenance costs are expected to be  
12          higher, despite a lag in hiring the additional maintenance personnel need to  
13          establish night maintenance shifts at Kahe and Waiau Power Plants. HECO is  
14          proceeding with the lease of nine distributed generating units to be installed at  
15          three substation sites, as discussed in HECO RT-7. Pension expenses have  
16          increased, as addressed in HECO RT-15.

17          Q.    Have there been any changes to the 2005 operating budget?

18          A.    As the year progresses, there are generally changes to the budget as cost  
19          estimates are firmed up and/or circumstances change, as described in HECO's  
20          response to CA-IR-14 and identified in other IR responses. Significant known  
21          changes affecting the test year estimates or relevant to IR responses, such as  
22          changes in the generating unit overhaul schedule, the elimination of CHP costs,  
23          the addition of substation DG costs, and updated plant addition estimates, were  
24          provided to the Consumer Advocate, Department of Defense and the  
25          Commission in the May 5 and June 15, 2005 update transmittals, and in HECO's

1 [REDACTED]

1 based on those expenses. The rate increase only applies on a going-forward  
2 basis, and will not be made effective retroactive to the beginning of the test year.  
3 Thus, the Company must continue to try to find creative ways to address its  
4 current financial results, as well as to handle unexpected budgetary challenges  
5 such as significantly higher overhaul costs. All discussions have, however, the  
6 following parameters: first we are mindful to be consistent with items raised in  
7 our test year filings and the need to disclose significant deviations from that  
8 budget; and second that no funding decision will ever be allowed to compromise  
9 the reliable operations of our system.

10 Amortization of Rate Case Expense

11 Q. What is HECO's response to the CA's argument (CA-T-2, pages 61-70) that  
12 amortization of its rate case expense should be made over a four year period vs. a  
13 three year period?

14 A. The decision on its next rate case application will depend on a number of factors,  
15 including the amount of rate relief granted in this proceeding, the impact and  
16 results of the Energy Efficiency Docket proceeding and the mechanism used to  
17 recover program related costs, the completion of significant capital expenditures  
18 and computer software development projects, increase in operations and  
19 maintenance expenses beyond the normalized amounts included in rates as a  
20 result of this rate case, and changes in kilowatthour sales and the cost of capital  
21 for the Company. Accordingly, based on the current planned investments and  
22 proposed treatment of lost margins for DSM programs, it is not unlikely that  
23 HECO's next rate case would be filed within three years from the conclusion of  
24 this proceeding. (HECO's response to CA-IR-259.) Ms. Faye Yamauchi  
25 addresses this issue in HECO RT-13.

1     CA Proposed Recommendations for Potential Reserve Adjustment Mechanisms

2     Q.     What are the CA proposed recommendations regarding the impact of the  
3           American Jobs Creation Act ("the Act") and potential accumulated deferred  
4           income tax ("ADIT") reserve adjustment?

5     A.     As discussed by Mr. Okada in HECO RT-17, there have been no Treasury  
6           Regulations that provide guidance as to how the Act should be interpreted, and  
7           how the additional deduction should be calculated. HECO's back-of-the-  
8           envelope calculation estimates no impact to HECO's tax liability for 2004, and  
9           no impact is reflected in determining the test year estimates. (See HECO's  
10          response to CA-IR-690.) The Consumer Advocate acknowledges that there has  
11          been no guidance as to how the Act should be interpreted and how the added  
12          deductions should be calculated, and does not reflect any impact of the Act in  
13          determining the test year estimates. However, the Consumer Advocate in CA-T-  
14          2 (page 101, lines 8-19) recommends that the Commission direct the Company  
15          to establish deferral accounts to capture any savings derived from the Act that  
16          have been excluded from the development of the overall revenue requirements,  
17          and subsequently provide the savings as a benefit to ratepayers. The Consumer  
18          Advocate points out that the Act provides for a phasing in of the full benefits of  
19          the legislation over the multi-year period (2005 through 2009), such that there  
20          should be additional tax savings in subsequent years. The Consumer Advocate  
21          further states that if a utility is typically allowed to defer costs or implement  
22          surcharge mechanisms to recover costs that are considered not to be collected  
23          through base rates, then it would logically and equitably follow that savings  
24          from events such as "known" federal income tax changes - not reflected in base  
25          rates - should also be deferred for future return to ratepayers.

1           In addition, as discussed by Mr. Okada in HECO RT-17, a favorable  
2           decision on a proposed application to the Internal Revenue Service to change a  
3           tax accounting methodology related to the timing of the deduction for certain  
4           overhead costs could result in a fairly significant additional deduction for tax  
5           purposes, and increase ADIT , which is a deduction to rate base. The Consumer  
6           Advocate in CA-T-2 (pages 105-106, lines 20-2) recommends that if a favorable  
7           decision is received subsequent to the decision in this case, the Commission  
8           order HECO to defer for future return to ratepayers any savings realized in the  
9           form of additional cost free ADIT reserves.

10       Q.    What is HECO's response to the Consumer Advocate's recommendations?

11       A.    The Consumer Advocate's recommendations are akin to single-issue ratemaking,  
12           which the Consumer Advocate has opposed in the past. For this reason, HECO  
13           must respectfully object to the CA's recommendations at this time. However,  
14           the Company would be willing to consider these recommendations in the context  
15           of an overall policy allowing the use of adjustment mechanisms for specific  
16           issues – provided the adjustment mechanism policy works both ways. Not only  
17           would a mechanism be considered for items that would result in a credit to  
18           customers, but the use of an adjustment mechanism would also apply to  
19           significant items that are beyond the control of the Company and result in a  
20           charge or cost increase to the customer. This will ensure that the adjustment  
21           mechanism policy is equitable and unbiased.

22       Reserve Capacity Shortfall

23       Q.    In your direct testimony, you addressed HECO's reserve capacity situation based  
24           on the Adequacy of Supply ("AOS") Report filed by HECO with the  
25           Commission on March 31, 2004 (the "AOS Report"). What did HECO's

1 analysis for the 2004 AOS Report indicate?

2 A. As stated on pages 10-11 of HECO T-1, our analysis indicated that generating  
3 system reliability would fall below HECO's 4.5 years per day reliability  
4 guideline (used for capacity planning) beginning in 2006, assuming that no new  
5 central-station generating capacity is added from 2004 through 2006, even if:  
6 (1) forecasted peak reduction benefits (estimated at 11 MW for 2004 – 2006)  
7 from continuation of existing energy efficiency DSM programs were acquired;  
8 (2) proposed peak reduction benefits (estimated at 28 MW for 2004 – 2006)  
9 from the two load management programs were acquired, as forecast in their  
10 respective applications; and (3) proposed utility Combined Heat and Power  
11 ("CHP") system impacts (estimated at 8 MW for 2004 – 2006) occurred as  
12 forecast in Docket No. 03-0366.

13 Q. What would happen if the assumed benefits were not obtained or if load grew  
14 faster than expected?

15 A. The 2004 AOS Report stated that, should the forecast peak reduction benefits  
16 from these programs not occur, then generating system reliability would be  
17 expected to fall below the 4.5 years per day reliability guideline threshold sooner  
18 than 2006. In addition, the report stated that HECO's ability to defer the need  
19 for the next central station generating unit addition (a CT for peaking purposes)  
20 to 2009, which is the earliest that permitting and installation of such a CT are  
21 expected to be completed, depended on whether (1) the load reduction benefits  
22 from planned load management and energy efficiency DSM programs were  
23 achieved, (2) distributed generation (in the form of customer-sited CHP systems)  
24 was implemented at the rate forecast, and (3) 40 MW or more of additional firm  
25 capacity (such as that to be provided pursuant to two amendments to HECO's

1 power purchase agreement with Kalaeloa Partners, L.P.) and/or load reduction  
2 measures (such as those included in the proposed new and expanded energy  
3 efficiency DSM programs) could be implemented.

4 If load grew faster than forecast, additional load reduction measures and/or  
5 firm capacity would be needed in the interim. I noted that load had grown  
6 somewhat faster than forecast in 2004, with a higher than forecast peak (by about  
7 14 MW) on October 12, 2004. In addition, HECO's existing generating units  
8 were being run harder and we had less flexibility in scheduling planned  
9 maintenance and overhauls, as a result of declining reserve margins resulting  
10 from load growth. Thus, the availability rates for the units had declined, even  
11 though they remained better than the industry averages for similar units. I also  
12 pointed out that lower availability rates for existing generation units could also  
13 increase the need for additional load reduction measures and/or firm capacity in  
14 the interim.

15 Q. What was the status of the measures in the base resource plan at the time of the  
16 application?

17 A. The load management programs had been approved, but commencement of the  
18 implementation of the programs was scheduled for the beginning of 2005,  
19 instead of 2004. New, expanded energy efficiency DSM programs were  
20 developed during the on-going integrated resource planning process for IRP-3,  
21 and approval of the new programs was requested in the rate case application  
22 pursuant to the Commission-approved stipulations allowing for the continuation  
23 of the existing energy efficiency DSM programs (although HECO may seek  
24 approval on a more accelerated basis as discussed later).

25 In October 2003, HECO filed an application for approval of a proposed

1 utility-owned Combined Heat and Power ("CHP") Program in Docket No.  
2 03-0366. The report noted that CHP system installations were behind schedule  
3 due to suspension of the CHP program application pending the generic DG  
4 docket, but that HECO planned to seek Commission approval for CHP system

5 contracts for customers on a case-by-case basis in the meantime, and had filed an  
6 application for approval of its first contract with a customer on October 28, 2004  
7 in Docket No. 04-0314.

8 HECO filed its application requesting approval of the amendments to the  
9 existing Power Purchase Agreement with Kalaeloa Partners L.P. on November 5,  
10 2004 in Docket No. 04-0320.

11 Q. What has happened since the filing of the application in the rate case?

12 A. HECO filed its 2005 Adequacy of Supply letter on March 10, 2005. Based on  
13 the analyses done for the letter, HECO indicated that it anticipates reserve  
14 capacity shortfalls in 2005 and projected these shortfalls to continue at least until  
15 2009, which is the earliest that HECO expects to be able to permit, acquire,  
16 install and place into commercial operation its next central station generating

1 additional firm capacity from Kalaeloa in 2005. The reserve capacity shortfall  
2 was projected to be approximately 50 to 70 MW in the 2006 to 2009 period,  
3 assuming that HECO is able to implement the aforementioned DSM programs as  
4 planned and obtains approval for and successfully implements a utility CHP  
5 Program (and/or individual CHP agreements), and to begin installing CHP  
6 systems beginning in mid 2006.

7 The 2005 AOS noted that, until sufficient generating capacity can be added  
8 to the system, HECO will experience a higher risk of generation-related  
9 customer outages. The actual risk of generation-related customer outages  
10 depends, among other factors, on (1) the actual peaks experienced by the system,  
11 (2) success in implementing the DSM programs and utility CHP projects, and  
12 customer participation in these programs, (3) the ability of HECO and its IPP  
13 partners to minimize unplanned or extended outages of existing generating units,  
14 and (4) the extent to which mitigation measures can be implemented. If actual  
15 peaks, due to weather impacts or other factors, are higher than forecasted, or if

16 generating units experience higher forced outage rates, and/or more and longer  
17 maintenance outages, the risk of generation-related customer outages will  
18 increase.

19 Q. Were any sensitivity analyses run?

20 A. Yes. The analysis done for the 2005 AOS letter assumed (1) the projected

1 implementation of a utility CHP Program (and/or individual CHP agreements),  
2 with CHP systems beginning to be installed beginning in mid 2006.

3 HECO considered two scenarios to analyze the impact if DSM and CHP  
4 peak reductions are lower than forecast, and/or generating unit forced outage  
5 rates are higher than forecast. One scenario considered the effect of disapproval  
6 or delayed implementation of, and lower-than-expected participation in the  
7 proposed DSM programs, and disallowance of HECO's participation in the CHP  
8 market, which resulted in estimated reserve capacity shortfalls of approximately  
9 60 to 110 MW during the 2005 to 2009 timeframe. If, in addition, forced outage  
10 rates are higher than forecast (by 20%), then it is estimated that the HECO  
11 system could experience reserve capacity shortfalls of approximately 90 to 130  
12 MW in the 2005 to 2009 period.

13 Q. What potential interim measures were identified in the 2005 AOS Report?

14 A. Measures that were being implemented, developed, or assessed for possible  
15 implementation, included installation of portable, leased DG units at  
16 HECO-controlled substation sites and other sites, a customer demand response  
17 program, incorporation of residential air conditioning loads into HECO's RDLC  
18 program, and communications with its customers to voluntarily reduce their  
19 electricity use during peak usage times. See 2005 AOS letter, pages 24-27.

20 Q. What is the current status of the base resource plan?

21 A. The measures in the base resource plan include enhanced energy efficiency DSM  
22 programs, HECO's existing load management programs with certain  
23 modification to enhance penetration of the market, utility-owned CHP systems,  
24 the additional capacity from Kalaeloa, and the addition of the CT in 2009. In  
25 addition, we are working to maintain the availability of our existing generating

1 units, which is becoming more of a challenge as the units become older and are  
2 run harder, and as HECO's flexibility to schedule maintenance outages is  
3 reduced due to our increasingly tight reserve margin. To briefly summarize the  
4 status:

5 Enhanced Energy Efficiency DSM

6 As a result of the bifurcation of the DSM portion of the rate case into a separate  
7 Energy Efficiency Docket, Docket No. 05-0069, the increased peak reduction  
8 benefits of the enhanced EE DSM Programs are now expected to be delayed  
9 from the July 2005 start date assumed for purposes of the AOS report. HECO's  
10 "plan" to expedite realization of some of the increased peak reduction benefits  
11 that were expected to result from the enhanced EE DSM programs, pending final  
12 resolution of the Energy Efficiency Docket, is to propose that (1) certain  
13 modifications be made to the existing C&I DSM Programs using the existing  
14 Letter of Modification mechanism, (2) certain measures included in the proposed  
15 enhanced EE DSM Programs (such as CFLs for Residential customers) be  
16 allowed to be implemented on an interim basis in the EE Docket, and (3) an  
17 expanded advertising "budget" be included in its pending rate case to be used (in  
18 conjunction with much of the existing corporate advertising "budget") to  
19 encourage energy conservation, through "behavioral changes" on the part of  
20 residential customers, in addition to their implementation of DSM measures  
21 included in the Residential DSM Programs. The net result, however, would still  
22 be somewhat lower impacts than if the Enhanced EE DSM Programs had been  
23 implemented beginning in July 2005, as was assumed for purposes of the AOS  
24 report.

25 One of the DSM programs included in the rate case application was the

proposed Residential Conservation Energy Awareness (“RCEA”) program, for which an application was filed for a two-year pilot program in Docket No. 03-0142. The stated purpose of the proposed pilot program was to determine if an aggressive communications program can change the level of customer energy awareness of energy options, and encourage customers to adopt energy efficient appliances and behavior, with the objective of helping to achieve energy savings and peak load reductions. By Decision and Order No. 21756, issued April 20, 2005, the Commission denied the application, as revised on October 7, 2004, without prejudice (based on concerns raised by the Consumer Advocate). At the same time, the Commission noted that (1) it “understands HECO’s need and desire to educate its residential customers about energy matters, including conservation,” and (2) “[a]n educational program, such as the RCEA Pilot Program may be better suited as one component of a portfolio of DSM measures, which may be considered in other proceedings before the Commission, if HECO so chooses.”

In light of the concerns raised by the Consumer Advocate, the Commission's decision, and the critical need to encourage residential customers

1 Load Control ("CIDLC") Programs. For example, prior to the Commission's  
2 approval of the RDLC and CIDLC Programs in Docket Nos. 03-0166 and  
3 03-0415, HECO stipulated with the CA, on June 30 and July 15, 2004, for the  
4 RDLC and CIDLC Programs respectively, to not recover direct labor,  
5 advertising, and miscellaneous costs of the programs through the IRP Surcharge,  
6 but to instead request recovery of these costs through base rates in the next  
7 (instant) rate case. HECO did this in order to accelerate the approval of the two  
8 load management program applications. The stipulation received PUC approval  
9 in October 2004. Under the stipulation HECO will not recover a portion of  
10 incurred program costs until a Decision and Order is issued by the PUC in this  
11 rate case.

12 As is indicated in HECO RT-10, HECO is proposing to increase its test year  
13 estimate of RDLC advertising expenses to reflect a full year direct mail  
14 campaign, telemarketing, and the addition of a customer recognition campaign to  
15 retain previously enrolled customers.

16 HECO also proposes to add an advertising component to the CIDLC budget  
17 included in base rates. The CIDLC Program advertising component will  
18 recognize commercial and industrial participants in print and radio, provide  
19 materials for display in their offices and/or storefronts identifying them as  
20 CIDLC Program participants, and any other advertising focused on reinforcing  
21 participation and/or recognizing participants. (See HECO RT-10, pages 5-9, and  
22 HECO's responses to CA-IR-446 and CA-IR-533.)

23 CHP Systems

24 HECO's efforts to implement CHP system projects were delayed by the  
25 suspension of the CHP program application, as requested by the CA. HECO's

1 subsequent efforts to pursue CHP system projects on a "Rule 4" contract basis,  
2 pending resolution of the Commission's DG investigation, were detailed in the  
3 DG Docket, Docket No. 03-0371. The first Rule 4 contract with Pacific Allied  
4 was filed in October 2004 in Docket No. 04-0314, but was suspended pending  
5 the DG investigation and then terminated by Pacific Allied. It is not expected  
6 that further DG agreements will be negotiated until there is a determination in  
7 Docket No. 03-0371 that it is appropriate for HECO to proceed with CHP  
8 projects on a utility basis.

9 Kalaeloa

10 At the end of 2003, HECO consented to Kalaeloa's proposed "M" upgrades to its  
11 combustion turbines, and facilitated the rescheduling of Kalaeloa's "C"  
12 inspection overhauls so that the upgrades could both be accomplished in 2004.  
13 This increased the amount of additional firm capacity potentially available from  
14 Kalaeloa from 9MW to 29MW. HECO then negotiated, filed and obtained  
15 approval for two amendments to the Kalaeloa Partners, L.P. amended PPA, as  
16 has been addressed in Docket No. 04-0320, and in this docket (which is the  
17 vehicle for HECO to recover the additional capacity payments for the additional  
18 megawatts of firm capacity to be provided by Kalaeloa).

19 Generating Unit Availability

20 The extensive efforts that HECO has taken and is continuing to take to maintain  
21 and/or improve the availability of its existing generating units have been detailed  
22 in HECO T-6 and related IR responses. The new "measures" include adding  
23 operational staff to allow for 24 hours a day, 7 days a week, operation of  
24 Honolulu 8 & 9 and Waiau 3&4, and the addition of night maintenance crews at  
25 the Kahe and Waiau power plants.

1           HECO's Next Generating Unit.

2           As is indicated in the AOS report, HECO earlier commenced the permitting  
3           process for a combustion turbine, in the 100 MW range, to be installed at its  
4           Campbell Industrial Park, Barbers Point Tank Farm site. In June 2005, HECO  
5           filed its application for approval of the new CT, and an application for approval  
6           of community benefit measures to mitigate the impact of the new generating unit  
7           on communities near the proposed generating unit site.

8           Q.     What is the status of the interim measures?

9           A.     Briefly, the status of the various measures is as follows:

10          Substation DG

11          Consideration of installing leased DG units at substation and other sites on an  
12          interim basis has been fast-tracked in 2005 given the delays in obtaining  
13          approvals needed to proceed with customer-sited CHP systems, which HECO  
14          considers to be a better long-term option for both HECO and its customers. As  
15          is indicated in HECO RT-7, HECO is on track with installing the nine DG units  
16          in the September-October 2005 timeframe. Mr. Scott Seu addresses this area in  
17          HECO RT-7 and accompanying exhibits, as well as HECO's responses to IRs  
18          (i.e., CA-IR-574, CA-IR-535).

19          Demand Load Response Program

20          Development of a voluntary demand load response program generally was  
21          expected to follow implementation of C&I Direct Load Control, but was moved  
22          up given the current capacity situation. HECO has retained a consultant to  
23          develop a demand load response program and expects to file an application with  
24          the Commission later in 2005. HECO does not expect that the demand load  
25          response program will impact its 2005 test year expenses, since HECO would

1 seek recovery of incremental costs under the DSM surcharge.

2 Residential Air Conditioning Direct Load Control

3 Direct load control of residential air conditioning was a measure that was  
4 evaluated, along with other measures, in the IRP-3 process. Following the filing  
5 of the Demand Load Response Program, HECO will pursue the development of  
6 a residential air conditioning load control program. HECO's Residential Direct  
7 Load Control (RDLC) Program, approved by the Commission in 2004, focuses  
8 on interrupting electric resistance water heaters only. HECO does not expect  
9 that the residential air conditioning load control program will impact its 2005 test  
10 year expenses, since HECO would seek recovery of incremental costs under the  
11 DSM surcharge.

12 Public Notification

13 This program refers to HECO's process to inform customers of and prepare  
14 customers for a potential generation-related customer outage and to ask for  
15 voluntary conservation should a system emergency occur such that HECO

---

---

---

16 anticipates that it may not be able to meet the demand for the day unless  
17 immediate action is taken. The public notification program is a tiered,  
18 systematic process of notifying the PUC, critical federal, state and local agencies,  
19 large customers, and the general public upon various generating conditions. The  
20 program's potential contribution will depend upon the success of HECO's  
21 integrated advertising campaign to encourage energy conservation and  
22 efficiency, and the conditions that exist at the time public notification is made.  
23 These conditions include, but are not limited to, the time of year, time of day,  
24 weather conditions (e.g., ambient temperature, wind speed, humidity), system

1 willingness and ability of our customers to reduce load at the time the public  
2 notification is given.

3 Q. Please explain what you mean by the Company's integrated advertising  
4 campaign?

5 A. Given current conditions, HECO has developed plans for a three-layered  
6 conservation and energy efficiency message, which will be critical through at  
7 least the year 2008. The first message revolves around the importance of using  
8 energy wisely at all times; the second emphasizes that it makes special sense to  
9 reduce energy use at peak; and the third creates a basis for dramatically cutting  
10 the use of electricity during an emergency. HECO would expand and enhance its  
11 efforts to educate customers about the need to conserve at these three levels.  
12 Additional messages would be developed and produced, and HECO would  
13 procure an expanded presence in print and broadcast media (including television  
14 and radio). Participation in HECO's DSM Programs (programs that these  
15 messages will refer to by name) will be identified as one of the actions our newly  
16 energy-aware customers can take to implement energy efficiency. Details about  
17 the Company's DSM Programs, however, will continue to be provided under  
18 HECO's separate DSM Program advertising budgets.

19 In conjunction with its integrated advertising campaign, HECO would work  
20 with the EPA to promote Energy Star as a residential and commercial solution  
21 for energy efficiency. For the residential market, HECO would develop  
22 educational advertisement and point of sale collateral materials. HECO would  
23 explore partnerships with appliance retailers and distributors. Commercial  
24 efforts would focus on design assistance and educational workshops and  
25 seminars for operations and facility managers. In addition, HECO would

1 undertake a complete redesign and consolidation of the conservation and energy  
2 efficiency sections of our website.

3 New Company Initiatives

4 Q. In your direct testimony, you provided insight into the new company initiatives  
5 that the Company is pursuing to address community concerns. Please  
6 summarize the reasons for these initiatives.

7 A. The Company, and the electric industry in general, are in the midst of changes in  
8 the way they do business. With greater expectations from customers and a  
9 heightened sense of community awareness and activism about projects, HECO's  
10 ability to manage its public standing and its operations is more critical than ever.  
11 HECO is proud of its record of reliability, of providing an adequate supply of  
12 power and of its continual work to strengthen its infrastructure. However, in  
13 order to continue to provide safe and reliable electric service to the community it  
14 serves, HECO is approaching its current situation in a different manner.

15 The production and delivery of energy is still the core of our business, and  
16 we strive to provide a reliable supply of electricity when and where our  
17 customers need it, at reasonable prices. But HECO's mission is much broader  
18 than that. HECO's mission includes: (1) encouraging and assisting its  
19 customers to use electricity wisely and efficiently, (2) providing customers with  
20 cost-effective choices, such as CHP systems that utilize waste heat from on-site  
21 electricity generators, so their needs can be met without burdening other  
22 customers. (3) promoting the increased use of Hawaii's commercially available



1 additional costs associated with HECO's underground cost-sharing policy?

2 A. Ms. Lorie Nagata in HECO RT-18 responds to the CA's position.

3 Q. What is the CA's position on recovery of the additional costs incurred under the  
4 Underground Cost-Sharing Policy?

5 A. The CA does not oppose rate recovery for those amounts at this time. CA-T-1,  
6 page 102, lines 17-20.

7 Q. What other comments do you have?

8 A. In Decision and Order No. 21003, issued by the Commission on May 27, 2004 in  
9 Docket No. 03-0260, the Commission approved HECO's request to spend  
10 approximately \$7,312,075 for the New Kuahua Substation Project. However, the  
11 Commission, required, among other things, that the CA and HECO submit a  
12 stipulated filing addressing the concerns raised in this docket regarding HECO's  
13 policies on underground lines and requiring contributions for the Commission's  
14 review and approval. D&O 21003 at 22.

15 Q. Have the CA and HECO reached an agreement?

16 A. The CA and HECO are working on HECO's policies on a going forward basis,  
17 and discussions between the parties are continuing. See CA-T-1, page 103, lines  
18 3-7. By Stipulated Procedural Order No. 21758, filed on April 21, 2005, the  
19 Commission granted an extension to July 29, 2005 to comply with the  
20 Commission's Decision and Order. However, due to the heavy regulatory  
21 workload of both parties, a second request for an extension, until October 31,  
22 2005, has been made with the Commission. HECO is optimistic that it will be  
23 able to work with the CA in addressing the concerns set forth in the Kuahua  
24 docket and submit a stipulated filing for the Commission's review and approval.

25

1     Energy Cost Adjustment Clause

2     Q.     What is the CA's position on the Company's continued use of the Energy Cost  
3             Adjustment Clause ("ECAC")?

4     A.     The CA does not object to HECO's continued use of the ECAC in its current  
5             form. CA-T-3, page 60, lines 4-8. HECO appreciates the CA's support for  
6             continuation of the ECAC.

7     Q.     Why does HECO still need an ECAC in light of the length of its current  
8             contracts and amendments to continue the contract for an additional ten year  
9             period?

10    A.     As stated in my direct testimony, pages 30-31, fuel prices under the current  
11             contracts and under the amendments are directly tied to various international and  
12             domestic indices, which are strongly influenced by global oil prices. One  
13             advantage of a 7-year term (and the amended contract for an additional ten years)  
14             is that certain adders to the base (indexed) oil prices have now been determined  
15             for the terms of the contracts (which will make the affected adders more  
16             "stable"). This however, will still not "stabilize" overall fuel prices, the bulk of  
17             which fluctuate with changes in the fuel price indices that are referenced in the  
18             contracts. Accordingly, fuel prices can still vary significantly with changes in  
19             the price of crude oil. HECO's units are 100% oil fired. Thus, fuel expense,  
20             which is one of HECO's largest expenses, will fluctuate with the price of crude  
21             oil. In addition, since a substantial portion of HECO's purchased energy  
22             payment rates (which are based on HECO's quarterly filed avoided energy costs)  
23             are tied to current fuel prices, HECO's purchased energy expense will also  
24             fluctuate with the price of oil. Continued use of an ECAC is the most reasonable  
25             means of fairly compensating HECO for its fuel and purchased energy expense

1 without unreasonably penalizing HECO or its customers. Mr. Alan Hee  
2 addresses this issue in HECO RT-10.

3  
4 OTHER MATTERS

5 Q. Are there any other matters upon which you plan to comment?

6 A. Yes. The CA, in CA-T-2 (pages 57-58, lines 14-4 and CA-T-3, page 26-27, lines  
7 10-6), expressed concern about the timeliness of certain responses to their  
8 information requests. Please explain the circumstances surrounding the filing of  
9 these responses.

10 A. The Company dedicated a substantial amount of time to respond to 692  
11 Information Requests (as well as 1682 subparts) from the CA and 142  
12 Information Requests (as well as 313 subparts) from the DOD. The amount of  
13 information provided amounts to 34, 2 ½ inch thick, three ring binders. In  
14 addition, the Company has made the appropriate people available for 16  
15 conferences between the CA, CA's consultants and HECO's witnesses to clarify  
16 and answer questions they had with respect to our responses.

17 The Company addressed information requests pertaining to specific areas  
18 such as the Company's Adequacy of Supply Report (28 Information Requests  
19 from the CA, not including subparts) and DSM issues that were bifurcated to the  
20 Energy Efficiency docket (27 Information Requests from the CA, not including  
21 subparts). The CA has in fact, acknowledged the numerous amount of  
22 information requests on specific technical areas in order to evaluate certain costs.  
23 (CA-T-2, page 81, lines 9-11.)

24 In addition, the Company provided a list of updates on certain revenue  
25 requirements inputs and additional details regarding a number of these changes,

1 and these updates were actually provided at an earlier state in the proceedings  
2 than updates that have sometimes been provided in prior rate cases.

3 However, it should be noted, the Company appreciates CA's and DOD's  
4 efforts to approach this proceeding in a professional manner and their  
5 willingness and patience to work with the Company in allowing for additional  
6 time to respond to their information requests.

7  
8 SUMMARY

9 Q. Please summarize your testimony.

10 A. HECO's total requested increase in revenues is \$ 63,035,000, or 5.20%, over  
11 revenues at present rates for the normalized 2005 test year (based on May 1,  
12 2005 fuel oil and purchased energy prices). HECO's total requested increase in  
13 revenues is \$50,877,000 at current effective rates for the normalized 2005 test  
14 years (using May 1, 2005 fuel and purchased energy prices). The requested rate  
15 increase is intended to give HECO a reasonable opportunity to earn an 8.83 %  
16 rate of return on average 2005 test year rate base of \$1,109,372,000 at proposed  
17 rates. HECO proposes to implement this requested rate increase in two steps, an  
18 Interim Rate Increase and a Final Increase. The Interim Rate Increase would be  
19 structured as surcharges to the various classes based on a percentage of the  
20 customer's bill (exclusive of Energy Cost Adjustment charges and other  
21 surcharges). HECO proposes to implement the Final Increase with the proposed  
22 rates and charges that are reflected in HECO-R-2224, or with such other rates  
23 and charges as approved by the Commission. If there is a settlement agreement  
24 reached between the parties regarding the class revenue requirement allocation,  
25 the interim increase would be implemented with the settlement agreement.

1           The need for rate relief is supported by the testimonies and exhibits of 20  
2 witnesses who have submitted 21 written testimonies, with supporting exhibits  
3 and workpapers. To facilitate a timely decision in this rate case, HECO has  
4 limited the number of issues by using, in most instances, the methodologies  
5 adopted by the Commission in HECO's last rate case, Docket No. 7766.

6       Q.   Does this conclude your testimony?

7       A.   Yes, it does.

8  
9  
10  
11  
12  
13  
14  
15  
16  
17  
18  
19  
20  
21  
22  
23  
24  
25

## **HAWAIIAN ELECTRIC COMPANY, INC.**

### **PUBLIC HEARING STATEMENT**

Docket No. 04-0113  
HECO Application for a Rate Increase

January 12, 2005  
Kaimuki High School Auditorium  
6:00 pm

### **INTRODUCTION**

Good evening Chairman Caliboso, Commissioner Kimura, Commissioner Kawelo, and members of the audience. I am Robbie Alm, Senior Vice President of Public Affairs for Hawaiian Electric Company, Inc.

First I'd like to thank our customers who are here tonight. We want to hear your concerns. We know that higher prices are hard on our customers. Our challenge is to balance costs with our customers' need for reliable service.

Tonight, I will briefly explain how much of an increase we are asking for, and where that money will go. I'll also tell you how the increase will affect our customers.

### **HOW MUCH REQUESTED?**

HECO is requesting a net increase of 7.3% or \$74.2 million in revenues. We are formally asking the Commission to approve a rate increase of \$98.6 million or a 9.9% increase in base revenues. However, part of that amount includes transferring the cost of existing energy efficiency programs from a surcharge line item on the electric bills into base electricity charges, which appear on another line on electric bills. Thus, the request is a net increase of approximately 7.3%.

### **WHY?**

Where would the money go? The primary reason for filing the rate case at this time is to continue and expand our very important energy efficiency and conservation programs. Over \$40 million, or nearly half of the request, will be used to continue and expand our energy efficiency and conservation programs, and to recover revenues that are currently recovered through the IRP surcharge through base rates instead. Our current energy efficiency programs feature rebates to help customers pay for energy

saving investments like solar water heating. We need to continue and expand these programs to help offset the increasing use of electricity on Oahu.

You may ask, "What does increasing electric rates have to do with conserving energy?" It is a logical question. In short, energy efficiency and conservation cost money to implement. Take our solar program, as an example. Among the many other costs to run the largest solar water heating program in the nation are: rebates, inspectors to ensure the quality of all systems installed under the program, and trained people to help customers analyze their energy used and determine if solar water heating would pay off for them.

HECO's existing energy efficiency programs, in effect since 1996, have paid out \$31 million in rebates, resulting in an additional 16,000 solar water heating systems, and thousands of projects to help businesses add energy saving and money saving devices such as efficient air conditioning, lighting, heating, industrial motors and other applications. HECO is also seeking to expand these programs, for example, with a plan to make available for qualified low-income families free energy-efficient devices such as compact fluorescent lighting, low-flow showerheads, water heater blankets and others.

In the long run, these programs can cost customers less than the cost for building multiple additional power plants to generate that electricity. Demand for electricity is rising quickly. In HECO's view, the single most critical thing we can do today is to reduce the demand for electricity by encouraging conservation and increasing the efficiency of how electricity is used. We are asking permission to continue this shift in focus when it comes to meeting energy needs.

The remainder of the requested increase is largely to help pay for a decade of reliability investments, and other measures we're taking to address increasing electricity use. This includes the cost to buy an additional 29 megawatts of power recently contracted, subject to commission approval, from independent power producer, Kalaeloa Partners.

Examples of major projects that HECO has built to improve reliable service which were completed since HECO's last rate case include:

- Major underground cable replacement work, including upgrading the underground cables in the critical downtown network which serves key government and business buildings.
- A new 46-kilovolt sub-transmission line from Waialua to Kuilima, placed in service in 1999.
- HECO's underground 138 kilovolt transmission lines connecting HECO's Archer, Kewalo and Kamoku substations, completed in 2002 and 2003. (These projects are part of an important southern transmission corridor that HECO has

been working on since the early 1990s to provide an alternative route to deliver power to customers.)

- The cost of undergrounding lower voltage distribution lines along Kamehameha Highway in Pearl City, completed in 1998.

A new, modern and more efficient underground distribution system is

REBUTTAL TESTIMONY OF  
CATHERINE M. HAZAMA

PLANNING ANALYST  
FORECASTS & RESEARCH DIVISION, CUSTOMER SOLUTIONS  
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Electricity Sales and Customer Forecast

1

INTRODUCTION

2

Q. Please state your name and business address.

3

A. My name is Catherine M. Hazama and my business address is 220 South King Street, Honolulu, Hawaii.

4

5

Q. Have you testified earlier in this docket?

6

A. Yes, my direct testimony is identified as HECO T-2.

7

Q. What will your rebuttal testimony cover?

8

9

1) the test year estimates for electricity sales (in gigawatt-hours, or GWh) and the number of customers,

10

11

2) the Consumer Advocate's ("CA") acceptance of the Company's test year estimates for sales and customers,

12

13

3) the Department of Defense's ("DOD") position on the Company's test year estimates for sales and customers,

14

15

4) the Company's May 2005 Sales Forecast, and

16

5) year-to-date June 2005 recorded sales and average number of customers.

17

My rebuttal testimony will show that the May 2005 Sales Forecast and the year-

18

to-date June 2005 actuals indicate that the Company's test year estimates are

19

somewhat higher in total than expected actuals for 2005.

1           291,765, as shown in HECO-R-201.

2           Q.    Have the rebuttal test year estimates been introduced previously in this  
3               proceeding?

4           A.    Yes. HECO provided the revised test year estimates to the parties on May 5,  
5               2005.

6           Q.    Why is the rebuttal test year estimate of electricity sales different from the direct  
7               testimony estimate of sales?

8           A.    The direct testimony test year sales estimates (based on HECO's June 2004 sales  
9               update) were revised on May 5, 2005 to reflect the following changes in  
10              assumptions:

- 11           1) the withdrawal of HECO's proposed Economic Development Rate ("EDR"),  
12              as specified in the Company's response to CA-IR-235,  
13           2) the delay in HECO's proposed Combined Heat and Power ("CHP") program,  
14              as specified in the Company's response to CA-IR-276, and  
15           3) the revision of Demand-Side Management ("DSM") program impacts to  
16              reflect only the continuation of existing programs.

17           The revisions are shown in HECO-R-202.

18           Q.    What is the difference between the rebuttal test year estimate of sales and the  
19               direct testimony estimate of sales?

20           A.    The test year difference is an increase of 13.2 GWh, as shown in HECO-R-202.

21           Q.    Did the Company revise its test year estimates of the average monthly number of  
22               customers?

23           A.    No. The estimates of average monthly number of customers by rate class  
24               reflected in HECO-R-201 are identical to the estimates in HECO-201 in my direct  
25               testimony. Thus, these estimates remained the same in my direct and rebuttal

1 testimonies and in the May 5, 2005 revision.

2 What are the CA's testimony sales volume estimates?

3 A. The CA stated that while it appears that HECO's forecast for 2005 has understated  
4 Residential sales volumes and overstated Commercial sales volumes in  
5 approximately offsetting amounts, the overall sales forecast in the Company's  
6 direct testimony appears reasonable and has been accepted by the CA (CA T-1).

1 HECO's response to CA-IR-647 did not change in the final adopted report  
2 included as HECO-RWP-203.

3 Q. Why is the Company providing the May 2005 forecast?

4 A. The Company is providing the May 2005 forecast for informational purposes  
5 because the forecast was not adopted until June 6<sup>th</sup>.

6 Q. How do the test year sales differ from the May 2005 sales forecast for 2005?

7 A. As shown on HECO-R-203, the May 2005 sales forecast is 56.5 GWh or 0.7%  
8 lower than the rebuttal test year estimates. Projected residential sales are higher  
9 ~~and commercial sales are lower in the May 2005 forecast~~

11 Q. What are the major differences between the rebuttal test year estimates and the  
12 May 2005 forecast for the residential sector?

13 A. As shown in HECO-R-204, the May 2005 forecast anticipates a lower average  
14 number of residential customers offset by a higher growth in use per customer

1 additions (excluding the impact of the Kukui Gardens conversion<sup>1</sup>) This  
2 resulted in a lower base upon which the 2005 additions would be applied.

3 2) Actual customer additions in 2005 continued to lag behind the 2005 rebuttal  
4 test year estimate, averaging only 2,213 in the first quarter of 2005<sup>2</sup>.

5 3) Given the lower actual 2004 average number of residential customers and the  
6 lower than expected first quarter 2005 customer additions, an average addition  
7 of almost 4,000 customers (as compared to the 3,000 forecasted amount in the  
8 June 2004 update) would be required to reach the average number of  
9 residential customers of 257,648 in 2005.

10 Partially offsetting the above trends was the assumption of continued strong  
11 activity in the residential real estate market and the relatively high number of  
12 building permits issued in 2004. Consideration of all of these factors resulted in a  
13 2005 residential customer additions projection of 2,700 and an average residential  
14 customer count of 256,370 (before the Kukui Gardens conversion)<sup>3</sup> for 2005 in  
15 the May 2005 forecast. This is higher than the average additions over the 2000 –  
16 2004 period of 2,500 customers per year<sup>4</sup>, but lower than the 3,000 customer  
17 additions assumed in the June 2004 update used for rebuttal test year purposes.

18 Q. Why is the estimated use per customer for 2005 from the May 2005 forecast  
19 higher than the rebuttal test year estimate?

20 A. In the June 2004 update, growth in residential use per customer was expected to  
21 increase by 1.3% in 2005 over a forecasted growth of 1.0% in 2004 (HECO-WP-  
22 201, page 34). Growth since 2001 had been very strong, likely because of

---

<sup>1</sup> See HECO T-2, pages 19-20.

<sup>2</sup> See HECO-RWP-203, page 30 (average =  $6,639 \div 3 = 2,213$ ).

<sup>3</sup> See HECO-RWP-203, page 32.

<sup>4</sup> See HECO's response to CA-IR-647, page 100.

historically low interest rates and increased penetration of air conditioning in

1 Manoa campus after the October 2004 flood. The Biomed building was restored  
2 to utility power by June 2005; however, the library is expected to remain on  
3 generator power until mid-2006. The losses at UH were not included in the June  
4 2004 update used for rebuttal test year purposes.

5 Q. Explain the changes in estimated growth due to large new construction projects?

6 A. Major sales growth was anticipated in 2005 for improvements at the Sand Island  
7 wastewater treatment plant, the new UH School of Medicine in Kakaako, and the  
8 State of Hawaii's fishing village at Piers 36-38 but the growth from these projects  
9 was about 13 GWh less than projected for the first quarter of 2005. Anticipated  
10 sales from these projects are expected to remain lower than the June 2004 update  
11 for all years of the forecast horizon. In addition, the Outrigger Beach Walk  
12 project began demolition of existing hotel properties. The closure of several  
13 hotels until 2008 was anticipated in the June 2004 update, but increased load at  
14 other properties expected to offset the loss has not materialized.

15 Q. In summary, what is the total difference between the May 2005 forecast and the  
16 rebuttal test year estimates for residential and commercial sales?

17 A. The May 2005 forecast is 56.5 GWh or 0.7% lower than the rebuttal test year  
18 estimate of 7,856.0 GWh.

19  
20 JUNE YEAR-TO-DATE 2005 SALES AND CUSTOMERS

21 Q. What is the expected growth in sales and customers for the rebuttal test year 2005  
22 over 2004?

23 A. The rebuttal test year growth in sales was projected to be 1.6% over recorded  
24 2004, and the average number of customers was also expected to grow by 1.6%.  
25 The test year estimates are shown in HECO-R-205 relative to 1995 – 2004

1        ..        recorded sales and average number of customers

2        Q.    What was the actual year-to-date June 2005 sales growth?

3        A.    As shown in HECO-R-206, June year-to-date 2005 sales were 7.6 GWh or 0.2%  
4            higher than the same period in 2004. Residential sales were 0.4% above 2004,  
5            while commercial sales were 0.1% above 2004.

6        Q.    What was the actual year-to-date June 2005 customer growth?

7        A.    The June year-to-date 2005 average number of customers was 2,486 or 0.9%  
8            above 2004 (see HECO-R-206). Residential customers in the first half of 2005  
9            were 2,391 or 0.9% above 2004, while commercial customers were 91 or 0.3%  
10          above 2004.

11      Q.    How does this compare to the test year estimates?

12      A.    As shown on HECO-R-207, actual June 2005 year-to-date sales and customers  
13          were below the June year-to-date test year rebuttal estimates by 1.4% and 0.6%,  
14          respectively. Residential sales were 9.1 GWh or 0.9% below and commercial  
15          sales were 43.4 GWh or 1.6% below forecast. Average residential customers  
16          were 1,238 or 0.5% below and commercial customers were 391 or 1.2% below  
17          forecast. Also, June year-to-date 2005 weather was warmer than the 1976 – 2004  
18          average. On a weather normalized basis, June year-to-date 2005 sales were 111.1

year-to-date results?

- A. The rebuttal test year estimates are higher than the May 2005 forecast and the June 2005 year-to-date actuals, as summarized in the tables below:

COMPARISON OF MAY 2005 FORECAST  
AND REBUTTAL TEST YEAR ESTIMATES

	May '05 Fcst	Rebuttal TY	Difference	%Diff
Sales (GWh)	7,799.5	7,856.0	(56.5)	-0.7%
Customers	290,697	291,765	(1,068)	-0.4%

Source: HECO-R-203

COMPARISON OF JUNE 2005 YEAR-TO-DATE ACTUALS  
AND REBUTTAL TEST YEAR ESTIMATES

	June YTD	Rebuttal YTD	Difference	%Diff
Sales (GWh)	3,720.5	3,774.4	(53.9)	-1.4%
Customers	289,214	290,839	(1,625)	-0.6%

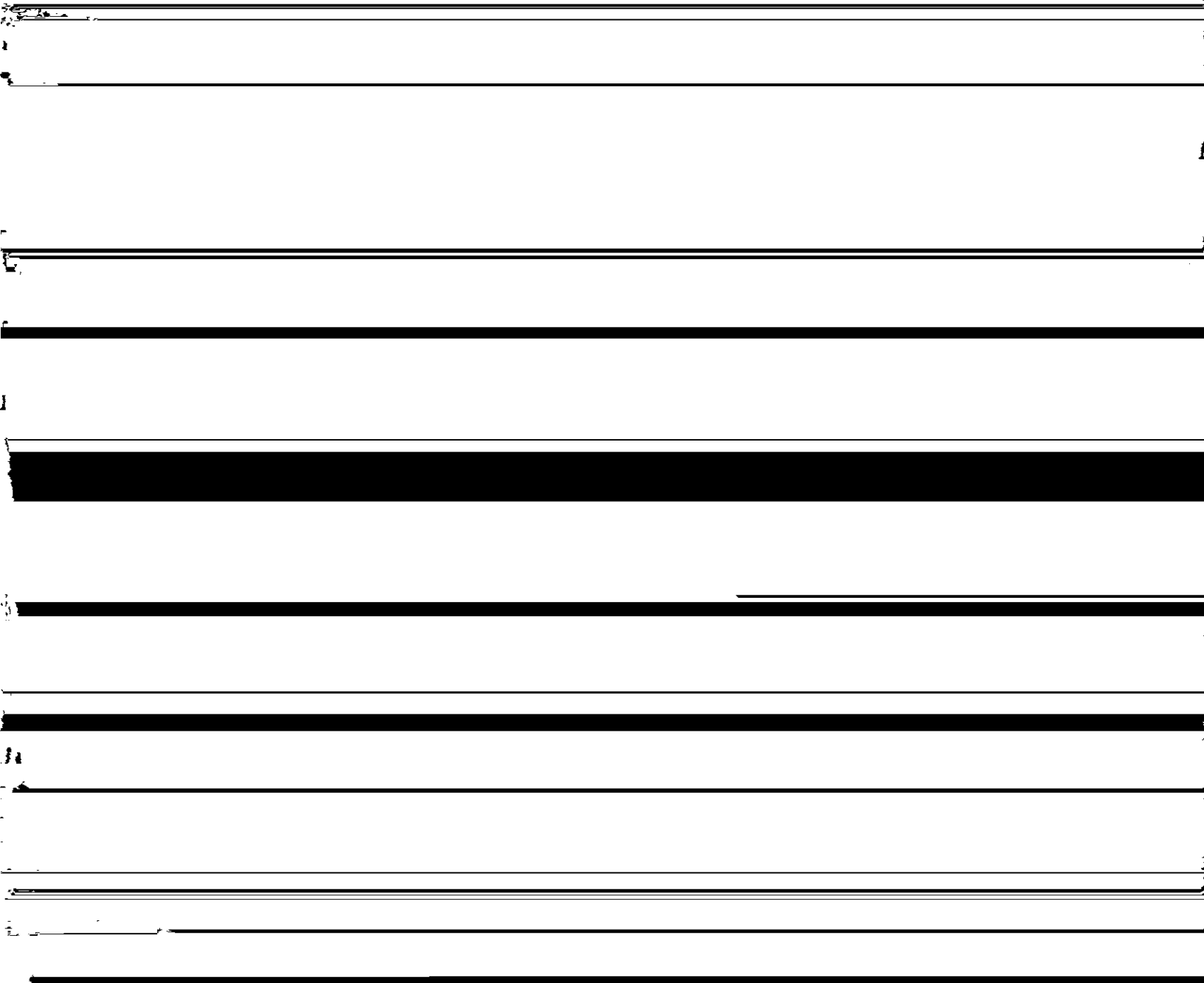
Source: HECO-R-207

While the rebuttal test year estimates appear to be overstated based on the comparisons above, and would have the impact of understating the test year revenue deficiency, the rebuttal test year estimates have not been revised and reflect the expectation of continued growth in sales and customers beyond the test year due to a strong Hawaii economy.

- Q. Please summarize your testimony on test year electricity sales and customers?

- A. The Company's rebuttal test year estimates for sales and average number of

1 customers, as shown in HECO-R-201, are 7,856.0 GWh and 291,765,  
2 approximately. The CA found the Company's test year sales and



3 estimates to be reasonable and accepted and incorporated them into their test year  
4 numbers. The DOD did not take a position on HECO's test year sales and  
5 customer estimates, but used the CA's estimated test year revenues based on the  
6 Company's May 5, 2005 test year sales and customer estimates.  
7

**Hawaiian Electric Company, Inc.**  
**TEST YEAR 2005 SALES FORECAST**

<u>Rate</u>	<u>GWh Sales</u>	<u>Average No. of Customers</u>
R	2,154.4	257,648
G	377.5	25,629
J	2,013.0	6,680
H	53.4	1,042
P	3,217.4	360
F	<u>40.3</u>	<u>406</u>
TOTAL	7,856.0	291,765

Source: May 5, 2005 transmittal letter to Ms. C. Kikuta and  
Dr. K. Davoodi, Attachment 1

**Hawaiian Electric Company, Inc.**  
**COMPARISON OF DIRECT TESTIMONY AND REBUTTAL TESTIMONY**  
**GWH SALES FORECAST**

<u>Rate</u>	<u>Direct Testimony TY Sales</u>	<u>Adjustments to Test Year Estimates</u>				<u>Rebuttal Testimony TY Sales</u>	<u>TY Sales Difference</u>
		<u>Utility CHP</u>	<u>3rd Party CHP</u>	<u>EDR</u>	<u>Future DSM</u>		
R	2,145.7	0.0	0.0	0.0	8.7	2,154.4	8.7
G	377.1	0.0	0.0	0.0	0.4	377.5	0.4
J	2,016.9	0.0	(1.2)	(0.2)	(2.5)	2,013.0	(3.9)
H	53.4	0.0	0.0	0.0	0.0	53.4	0.0
P	3,209.4	1.4	5.6	0.0	1.0	3,217.4	8.0
F	<u>40.3</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>40.3</u>	<u>0.0</u>
TOTAL	7,842.8	1.4	4.4	(0.2)	7.6	7,856.0	13.2

Source: May 5, 2005 transmittal letter to Ms. C. Kikuta and Dr. K. Davoodi, Attachment 1

**Hawaiian Electric Company, Inc.**  
**COMPARISON OF MAY 2005 SALES & CUSTOMER FORECAST**  
**VERSUS REBUTTAL TEST YEAR 2005 ESTIMATES**

Rate	May 05 Fcst GWh Sales	Rebuttal TY GWh Sales	May 2005 less Rebuttal Difference	% Diff
R	2,189.2	2,154.4	34.8	1.6%
G	370.2	377.5	(7.3)	-1.9%
J	2,018.1	2,013.0	5.1	0.3%
H	54.6	53.4	1.2	2.2%
P	3,129.8	3,217.4	(87.6)	-2.7%
F	37.6	40.3	(2.7)	-6.7%
<b>TOTAL</b>	<b>7,799.5</b>	<b>7,856.0</b>	<b>(56.5)</b>	<b>-0.7%</b>
Commercial *	5,572.7	5,661.3	(88.6)	-1.6%

Rate	May 05 Fcst Average No. of Customers	Rebuttal TY Average No. of Customers	May 2005 less Rebuttal Difference	% Diff
R	256,876	257,648	(772)	-0.3%
G	25,430	25,629	(199)	-0.8%
J	6,584	6,680	(96)	-1.4%
H	1,034	1,042	(8)	-0.8%
P	355	360	(5)	-1.4%
F	418	406	12	3.0%
<b>TOTAL</b>	<b>290,697</b>	<b>291,765</b>	<b>(1,068)</b>	<b>-0.4%</b>
Commercial *	33,403	33,711	(308)	-0.9%

\* Not including Schedule F.

Source: May 2005 forecast, HECO-RWP-203

**Hawaiian Electric Company, Inc.**

**RESIDENTIAL RECORDED SALES  
MAY 2005 FORECAST VS. REBUTTAL TEST YEAR \***

	May 2005 Forecast	Rebuttal TY 2005	Difference	
			Amt	%
MWH Sales	2,189,200	2,154,400	34,800	1.6%
Bills	256,876	257,648	-772	-0.3%
KWH Use per Bill	8,522	8,362	160.604	1.9%

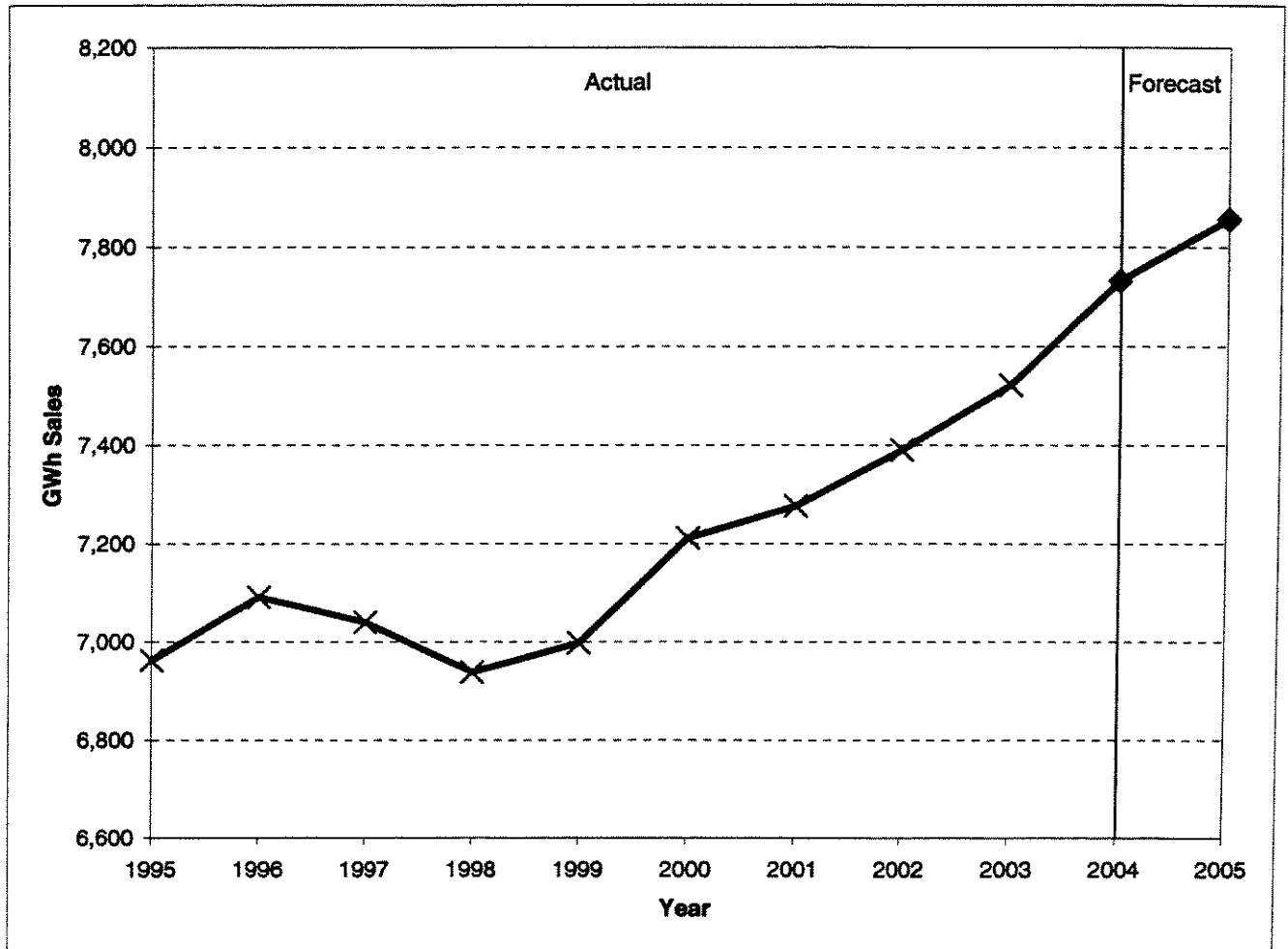
Change in Customers x Use per Bill = Difference in Sales					
-772	x	8,522	=	-6,579,293	KWH

Change in Use Per Bill x Customers = Difference in Sales					
160.604	x	257,648	=	41,379,293	KWH

Total:	34,800,000	KWH
--------	------------	-----

\* June 2004 sales update adjusted for test year EDR, CHP, and DSM assumptions.

### TOTAL SYSTEM SALES



Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
GWh Sales *	6,962.8	7,091.1	7,040.3	6,938.3	6,997.9	7,211.8	7,276.7	7,390.4	7,522.2	7,732.8	7,856.0
Customers	268,223	270,294	271,409	272,316	273,967	276,394	279,479	281,871	284,530	287,258	291,765

\* 1995-2004: non-weather normalized recorded, 2005: weather normalized forecast

**Hawaiian Electric Company, Inc.**  
**COMPARISON OF 2005 VERSUS 2004**  
**JUNE YEAR-TO-DATE**  
**Recorded Sales**

<u>Rate</u>	<u>Jun YTD 2005 GWh Sales</u>	<u>Jun YTD 2004 GWh Sales</u>	<u>2005 vs 2004 Difference</u>	<u>% Diff</u>
R	1,034.2	1,030.2	4.0	0.4%
G	179.4	178.2	1.2	0.7%
J	972.5	946.2	26.3	2.8%
H	26.2	28.3	(2.1)	-7.4%
P	1,489.5	1,511.3	(21.8)	-1.4%
F	18.7	18.7	0.0	0.0%
<b>TOTAL</b>	<b>3,720.5</b>	<b>3,712.9</b>	<b>7.6</b>	<b>0.2%</b>
<b>Commercial *</b>	<b>2,667.6</b>	<b>2,664.0</b>	<b>3.6</b>	<b>0.1%</b>

<u>Rate</u>	<u>Jun YTD 2005 Average No. of Customers</u>	<u>Jun YTD 2004 Average No. of Customers</u>	<u>2005 vs 2004 Difference</u>	<u>% Diff</u>
R	255,529	253,138	2,391	0.9%
G	25,453	25,262	191	0.8%
J	6,510	6,476	34	0.5%
H	958	1,093	(135)	-12.4%
P	355	354	1	0.3%
F	409	405	4	1.0%
<b>TOTAL</b>	<b>289,214</b>	<b>286,728</b>	<b>2,486</b>	<b>0.9%</b>
<b>Commercial *</b>	<b>33,276</b>	<b>33,185</b>	<b>91</b>	<b>0.3%</b>

\* Not including Schedule F.

**Hawaiian Electric Company, Inc.**  
**COMPARISON OF JUNE YEAR-TO-DATE 2005**  
**VERSUS TEST YEAR FORECAST**  
**Recorded Sales**

Rate	Jun YTD 2005 GWh Sales	Rebuttal TY YTD GWh Sales	2005 vs TY Difference	% Diff
R	1,034.2	1,043.3	(9.1)	-0.9%
G	179.4	182.3	(2.9)	-1.6%
J	972.5	961.8	10.7	1.1%
H	26.2	24.9	1.3	5.2%
P	1,489.5	1,542.0	(52.5)	-3.4%
F	18.7	20.1	(1.4)	-7.0%
<b>TOTAL</b>	<b>3,720.5</b>	<b>3,774.4</b>	<b>(53.9)</b>	<b>-1.4%</b>
Commercial *	2,667.6	2,711.0	(43.4)	-1.6%

Rate	Jun YTD 2005 Average No. of Customers	Rebuttal TY YTD Avg. No. of Customers	2005 vs TY Difference	% Diff
R	255,529	256,767	(1,238)	-0.5%
G	25,453	25,590	(137)	-0.5%
J	6,510	6,651	(141)	-2.1%
H	958	1,066	(108)	-10.1%
P	355	360	(5)	-1.4%
F	409	405	4	1.0%
<b>TOTAL</b>	<b>289,214</b>	<b>290,839</b>	<b>(1,625)</b>	<b>-0.6%</b>

Commercial *	22,070	22,007	(63)	-0.3%
--------------	--------	--------	------	-------

**Hawaiian Electric Company, Inc.**  
**COMPARISON OF JUNE YEAR-TO-DATE 2005**  
**VERSUS TEST YEAR FORECAST**  
**Weather Normalized Recorded Sales**

<u>Rate</u>	<u>Weather Normalized Jun YTD 2005 GWh Sales</u>	<u>Test Year YTD GWh Sales</u>	<u>2005 vs 2004 Difference</u>	<u>% Diff</u>
R	1,027.7	1,043.3	(15.6)	-1.5%
G	176.0	182.3	(6.3)	-3.5%
J	954.0	961.8	(7.8)	-0.8%
H	25.7	24.9	0.8	3.2%
P	1,461.2	1,542.0	(80.8)	-5.2%
F	18.7	20.1	(1.4)	-7.0%
<b>TOTAL</b>	<b>3,663.3</b>	<b>3,774.4</b>	<b>(111.1)</b>	<b>-2.9%</b>
<b>Commercial *</b>	<b>2,616.9</b>	<b>2,711.0</b>	<b>(94.1)</b>	<b>-3.5%</b>

\* Not including Schedule F.

TESTIMONY OF  
PETER C. YOUNG

RATE ANALYST, PRICING DIVISION  
ENERGY SERVICES DEPARTMENT  
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Electric Revenues and Other Operating Revenues

INTRODUCTION

1

2 Q. Please state your name and position.

3 A. My name is Peter C. Young and I am a Rate Analyst with the Pricing Division of  
4 the Energy Services Department at the Hawaiian Electric Company.

5 Q. Have you sponsored other written testimony in this docket?

6 A. Yes. I submitted direct testimony HECO T-3 on Electric Revenues and Other  
7 Operating Revenues. I am adopting direct testimony HECO T-22 and am  
8 providing rebuttal testimony for Cost-of-Service and Rate Design in HECO RT-  
9 22.

10 Q. What do you cover in HECO RT-3?

11 ~~My rebuttal testimony in HECO RT-3 covers the following:~~

1 and proposed rates are \$1,218,266,800 and \$1,280,574,800, respectively, as

2 1. HECO-R-301. The revised proposed electric sales revenues for test year

3 2005 reflect an increase of \$62,308,000 or 5.11% above the estimated electric  
4 sales revenues at present rates.

5 Q. How is the revised allocation of revenues at proposed rates determined?

6 A. The determination of the revised allocation of revenues at proposed rates,  
7 reflected in HECO-R-301 and HECO-R-302, is discussed in the cost-of-service  
8 and rate design testimony in HECO-RT-22.

9 Comparison with Direct Testimony Electric Revenues

10 Q. How does HECO's revised test year electric sales revenue estimate at present rates

1           7)    A revised estimate of the Rate Adjustment percentage factor; and

2           8)    Revised estimates of adjustments for minimum bills, employee discount,  
3                and apartment house billing discount.

4       Q.    What is the revised estimate of test year 2005 sales?

5       A.    The revised estimate of test year 2005 sales is discussed by Ms. Hazama in HECO  
6           RT-2.

7       Q.    What is the revised estimate of Schedule PP's power factor?

8       A.    The Schedule PP power factor was revised from 99% used in direct testimony to  
9           95%, based on HECO's response to CA-IR-532.

10      Q.    What is the revised estimate of the Energy Cost Adjustment Factor?

11      A.    The revised estimate of the Energy Cost Adjustment Factor at present rates is  
12           5.414 cents per kWh, which compares to the 2.586 cents per kWh used in  
13           direct testimony. The revised estimate of the Energy Cost Adjustment Factor  
14           at present rates is discussed by Mr. Hee in HECO RT-10.

15      Q.    What are the revised estimates of Rider Adjustments for customers on Rider M  
16           and Rider I?

17      A.    The revised estimate of Rider Adjustments for customers on Rider M and Rider I  
18           at present rates and proposed rates are presented in the adjustments to revenues  
19           on rate Schedules J, PS, and PP shown in HECO-RWP-302.

20      Q.    Why is the estimate of Rider Adjustments for customers on Rider M and Rider I  
21           being revised?

22      A.    The estimate of Rider Adjustments for customers on Rider M and Rider I is being  
23           revised for additional potential customers and for a change in the method of  
24           estimating the rider adjustment for individual potential rider customers, to show  
25           an average impact for the test year instead of an annualized impact, as indicated in

1 HECO's response to HECO/DOD-IR-11-1, subpart b.

2 Q. Why are additional potential rider customers being added?

3           A. As indicated in HECO's response to HECO/DOD-IR-11-1, subpart b., HECO  
4 is including 14 Rider I customers and 6 Rider M customers that were not  
5 previously identified in direct testimony. The 14 potential Rider I customers are  
6 now included because they have interruptible loads between 100 kW and 500 kW  
7 and would be eligible for Rider I service under the revision to Rider I proposed in  
8 direct testimony at HECO T-22, page 43. The six potential Rider M customers  
9 not previously identified in direct testimony included the customer identified in  
10 HECO's response to CA-IR-584, two customers that have recently completed rate  
11 analysis review that are expected to sign Rider M contracts shortly, and three  
12 customers that emerged from the survey of HECO account managers for potential  
13 new Rider I customers that were assessed to be better as potential Rider M  
14 customers.

15 Q. Why is it important for the rider adjustments to reflect the growth in rider  
16 customers?

13 A. B. ----- J. L. HECOO's memorandum to HECOO/DOD ID 11-1 submitted to -----

1 Q. Why is it reasonable for the Company to include potential rider customers?

2 A. It is reasonable for the Company to include potential rider customers in its  
3 estimate of rider adjustments because there is a historical pattern of growth in  
4 rider customer participation at HECO. The growth in customer participation in  
5 Riders M, T, I, and Schedule U from 1996 to 2004, since the 1995 test year where  
6 current HECO rates were set, is shown in HECO-R-304. There are 31 customers  
7 who have signed for Rider M, Rider T, Rider I or Schedule U service since 1995.  
8 The Company believes that it is reasonable to expect similar growth in rider  
9 participation in future years, including years beyond the 2005 test year.

10 Q. Why are the revenue adjustments for Rider EDP and Schedule GED eliminated in

1 discount, and apartment house billing discount?

2 A. The revised estimates of adjustments for minimum bills, employee discount, and  
3 apartment house billing discount are shown in the revenue adjustments to  
4 Schedules R, G, and F which are shown in HECO-RWP-302.

5 Q. Why are estimates of adjustments for minimum bills, employee discount, and  
6 apartment house billing discount being revised?

7 A. The estimates of adjustments for minimum bills, employee discount, and  
8 apartment house billing discount are revised because of the revision to the  
9 Energy Cost Adjustment Factor, which impacts the calculation of these items.

10 Q. How does HECO's revised test year electric sales revenue estimate at proposed  
11 rates compare with that presented in its direct testimony?

12 A. HECO's revised estimate of electric sales revenues at proposed rates is  
13 \$188,691,800 higher than the estimate provided in its direct testimony. A  
14 comparison by rate class is presented in HECO-R-306.

15 Q. Why is the rebuttal testimony estimate of electric sales revenue at proposed rates  
16 different than the direct testimony estimate?

17 A. The Company revised its test year 2005 estimates of electric sales revenue at  
18 proposed rates for changes in items included in revenue requirements. The  
19 reasons for these changes between direct testimony and rebuttal testimony are  
20 discussed by the other HECO witnesses in the case.

21

22 OTHER OPERATING REVENUES

23 Q. What is HECO's revised estimate of test year 2005 other operating revenues at  
24 present and proposed rates?

25 A. HECO's revised estimate of test year 2005 other operating revenues at present

1 rates and proposed rates are \$3,335,000 and \$4,062,500, respectively, as shown in  
2 HECO-R-307. The revised proposed other operating revenues for test year 2005  
3 reflect an increase of \$727,500 or about 22% above the estimated other operating  
4 revenues at present rates.

5 Comparison with Direct Testimony Other Operating Revenues

6 Q. How does HECO's revised estimate of test year other operating revenue compare  
7 with that presented in its direct testimony?

8 A. HECO's revised estimate of test year other operating revenue at present rates and  
9 proposed rates is compared with the estimates presented in direct testimony in  
10 HECO-R-308.

11 Q. Why are the estimates of other operating revenue revised?

12 A. HECO's revised estimates of other operating revenue at both present rates and  
13 proposed rates primarily reflect changes in the estimate of late payment charges  
14 and changes in the estimates of amortization of gain on sale and electric property  
15 rent.

16 Q. Why is the estimate of late payment charges revised?

17 A. The estimate of late payment charges at both present and proposed rates is revised  
18 due to the revised estimates of electric sales revenue. Late payment charges are  
19 estimated at 0.1% of electric sales revenue, as shown in HECO's response to CA-  
20 IR-167.

21 Q. Why are the estimates of amortization of gain on sale and electric property rent  
22 revised?

23 A. The estimates of amortization of gain on sale and electric property rent at both  
24 present and proposed rates are revised as indicated in HECO's response to  
25 HECO/DOD-IR-9-2, subpart a, and its accompanying table on Miscellaneous

1 Revenues.

2 Comparison with CA's and DOD's Revenue Estimates

3 Q. Are there differences between HECO, the CA, and the DOD with respect to the  
4 test year estimates of electric revenue?

5 A. Yes. A comparison of HECO's rebuttal estimate of total operating revenues with  
6 the CA's and the DOD's respective estimate of total operating revenues at present  
7 rates is presented in HECO-R-309. HECO's rebuttal estimate of total operating  
8 revenues at present rates is \$29,540,000 lower than the CA's estimate and  
9 \$29,680,000 lower than the DOD's estimate. A comparison of HECO's rebuttal  
10 estimates of total operating revenues with the CA's and the DOD's respective  
11 estimates of total operating revenues revenue at proposed rates is presented in  
12 HECO-R-310. HECO's rebuttal estimate of total operating revenues at present  
13 rates is \$10,019,000 higher than the CA's estimate and \$14,045,000 higher than  
14 the DOD's estimate.

15 Q. What are the differences between the Company's revenue estimate at present rates  
16 and the CA's revenue estimate at present rates?

17 A. The Company and the CA differ at present rates due to differences in the  
18 following:

- 19 1) calculation of the impact of the sales adjustment;
- 20 2) Energy Cost Adjustment Factor assumption;
- 21 3) Rider Adjustments;
- 22 4) the estimate of amortization of gain on sale; and
- 23 5) the late payment charge revenues.

24 Q. Why do the Company and the CA differ on the calculation of the impact of the  
25 sales adjustment?

1       A.   The Company has re-calculated revenues at present rates at the revised rebuttal  
2           sales levels using the same methodology employed in direct testimony, which is  
3           illustrated in HECO-RWP-302. The CA employed a weighted average of the  
4           energy, demand, and energy cost adjustment factor revenues from HECO's direct  
5           testimony to estimate the change in revenues due to the revised sales, as shown in  
6           CA-101, Schedule C-1.

7       Q.   Why is the Company's methodology more reasonable than the CA's?

8       A.   The CA's method does not take into account adjustments for minimum bills and  
9           the employee discount, and incorrectly tries to estimate the impact on demand  
10          revenues by using only the change in kWh instead of estimating the change in the  
11          billing kW.

12      Q.   How do the Company and the CA differ on the Energy Cost Adjustment Factor?

13      A.   The Company uses 5.414 ¢/kWh for the Energy Cost Adjustment Factor in  
14          rebuttal testimony. The CA uses 5.789 ¢/kWh for the Energy Cost Adjustment  
15          Factor, as shown in CA-101, Schedule C-4. Mr. Hee discusses the Energy Cost  
16          Adjustment Factor in HECO RT-10.

17      Q.   Why do the Company and the CA differ on the impact of Rider Adjustments?

18      A.   The CA's position is that Rider Adjustments from potential rider customers  
19          should not be included in the calculation of present revenues (CA-T-1, page 23).  
20          The Company's position, as described above and in the Company's response to  
21          HECO/DOD-IR-11-1 is that the rider adjustments from all potential rider  
22          customers should be included in the calculation of present revenues. Rider  
23          adjustments do not affect revenue requirements. Once final rates are set, the  
24          emergence of additional rider customers who have not been provided for through  
25          rider adjustments may have a negative impact on the Company's ability to earn its

1 allowed rate of return. As previously discussed, recent history shows that the  
2 Company adds new rider customers regularly, which supports including potential  
3 customer rider adjustments in the revenue estimates.

4 Q. Why do the Company and the CA differ on the estimate of the amortization of  
5 gain on sale?

6 A. The Company revised its estimate of amortization of gain on sale in its response to  
7 HECO/DOD-IR-9-2. The DOD accepts this position, as shown in DOD-115, and  
8 has adjusted its estimate of amortization of gain on sale accordingly. The CA also  
9 accepts the Company's revisions, with the exception of the amortization of gain  
10 on sale associated with the Lilipuna transaction. The CA's position is that this  
11 amortization expires during the test year and will not continue while the new rates  
12 are in effect (CA-T-1, pages 26-27). In the CA's response to HECO/CA-IR-106,  
13 the CA argues that it is necessary to normalize the test year to remove the partial  
14 year amortization amount included by HECO for the Lilipuna transaction.

15 Q. What is the Company's position on the Lilipuna transaction?

16 A. The Company's position is the amortization of gain from the Lilipuna transaction  
17 should remain in the estimate of total operating revenues.

18 Q. What are the differences between the Company and the CA on late payment  
19 revenue?

20 A. The Company has estimated late payment charges revenue at 0.1% of electric  
21 sales revenue and has adjusted the estimate to reflect revised electric sales  
22 revenues. Both the CA and the DOD use the Company's direct testimony  
23 estimate of late payment charges at present rates but do not adjust the estimate at  
24 proposed rates nor do they adjust revenue requirements for any changes in late  
25 payment charges. The Company's position is that late payment charge revenues

1 should be adjusted to 0.1% of electric sales revenues.

2 Q. What are the differences between the Company's revenue estimate at present rates  
3 and the DOD's revenue estimate at present rates?

5 following:

6            1) the calculation of the impact of the sales adjustment;

1 taxes. HECO discusses rate of return on common equity in HECO RT-20 and rate  
2 of return on rate base in HECO RT-21.

3  
4 SUMMARY

5 Q. Please summarize your testimony.

6 A. HECO's revised estimate of test year 2005 electric sales revenues at present rates  
7 and proposed rates are \$1,218,266,800 and \$1,280,574,800, respectively. The  
8 revised proposed electric sales revenues for test year 2005 reflect an increase of  
9 \$62,308,000 or 5.11% above the estimated electric sales revenues at present rates.

---

10 HECO's revised estimate of test year 2005 other operating revenues at  
11 present rates and proposed rates are \$3,335,000 and \$4,062,500, respectively. The  
12 revised proposed other operating revenues for test year 2005 reflect an increase of  
13 \$727,500 or about 22% above the estimated other operating revenues at present  
14 rates.

15 The Company's method of adjusting electric sales revenues for the revised  
16 estimate of sales is reasonable. The CA's method does not take into account  
17 adjustments for minimum bills and the employee discount, and incorrectly tries to  
18 estimate the impact on demand revenues by using only the change in kWh instead  
19 of estimating the change in the billing kW.

20 Rider adjustments from all potential rider customers should be included in

---

21 the estimate of revenues. Rider adjustments do not affect revenue requirements.

1 customers regularly, which supports including potential customer rider  
2 adjustments in the revenue estimates.

3 Q. Does this conclude your testimony?

4 A. Yes.

5

6

7

8

9

10

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

HAWAIIAN ELECTRIC COMPANY, INC.  
DOCKET NO. 04-0113  
TEST YEAR 2005 REBUTTAL

2005 TEST YEAR ELECTRIC SALES REVENUE

Rate Class	At Present Rates (\$000s)	At Proposed Rates (\$000s)	Proposed Increase (\$000s)	Increase (%)
Schedule R	\$379,853.7	\$404,126.4	\$24,272.7	6.39%
Schedule G	\$71,429.0	\$74,969.6	\$3,540.6	4.96%
Schedule J	\$311,441.9	\$323,401.3	\$11,959.4	3.84%
Schedule H	\$8,424.0	\$8,962.3	\$538.3	6.39%
<del>Schedule DD</del>	<del>\$104,040.0</del>	<del>\$109,404.0</del>	<del>\$5,364.0</del>	<del>5.06%</del>
<hr/>				
<hr/>				
<hr/>				
<hr/>				
<hr/>				
<hr/>				
<hr/>				
<hr/>				
<hr/>				
<hr/>				
Schedule PP	\$293,533.4	\$308,083.3	\$14,549.9	4.96%
Schedule PT	\$23,101.4	\$23,988.5	\$887.1	3.84%
Schedule F	\$6,437.2	\$6,848.5	\$411.3	6.39%
Total Electric Sales Revenue	<u>\$1,218,266.8</u>	<u>\$1,280,574.8</u>	<u>\$62,308.0</u>	<u>5.11%</u>

HAWAIIAN ELECTRIC COMPANY, INC.  
Docket No. 04-0113, Test-Year 2005 REBUTTAL TESTIMONY  
SCHEDULE R - RESIDENTIAL SERVICE

ESTIMATE OF TEST YEAR REVENUES

	<u>PRESENT RATES</u>			<u>PROPOSED RATES</u>	
	<u>BILLING</u> <u>UNITS</u>	<u>UNIT PRICE</u>	<u>REVENUES</u> <u>\$1000S</u>	<u>UNIT PRICE</u>	<u>REVENUES</u> <u>\$1000S</u>
<u>ENERGY CHARGE:</u>	<u>(MWH)</u>	<u>¢/kWh</u>		<u>¢/kWh</u>	
NON-FUEL ENERGY CHARGE	2,154,400	7.7814	\$167,642.5	8.4415	\$181,863.7
BASE FUEL ENERGY CHARGE	2,154,400	3.5140	<u>\$75,705.6</u>	8.8903	<u>\$191,532.6</u>
SUBTOTAL			\$243,348.1		\$373,396.3
<u>CUSTOMER CHARGE:</u>	<u>BILLS</u>	<u>\$/MONTH</u>		<u>\$/MONTH</u>	
1 PHASE CHARGE	3,090,230	7.00	\$21,631.6	10.00	\$30,902.3
3 PHASE CHARGE	<u>1,546</u>	15.00	<u>\$23.2</u>	20.00	<u>\$30.9</u>
SUBTOTAL	3,091,776		\$21,654.8		\$30,933.2
<u>ADJUSTMENTS:</u>					
FUEL OIL ADJUSTMENT:	¢/KWH	5.414	\$116,639.2	-	\$0.0
RATE ADJUSTMENT (AES REFUND):	(%)	-0.400%	(\$1,057.3)	-	\$0.0
MISCELLANEOUS **:			(\$731.1)		(\$202.5)
SUBTOTAL			<u>\$114,850.8</u>		<u>(\$202.5)</u>
TOTAL REVENUES			\$379,853.7		\$404,127.0

\*\* INCLUDES Schedule E Adj., Minimum Bill Adj., Apartment House Discount, and Residential TOU Adjustment.

HAWAIIAN ELECTRIC COMPANY, INC.  
Docket No. 04-0113, Test-Year 2005  
SCHEDULE G - GENERAL SERVICE NON-DEMAND

ESTIMATE OF TEST YEAR REVENUES

	<u>PRESENT RATES</u>			<u>PROPOSED RATES</u>	
	<u>BILLING UNITS</u>	<u>UNIT PRICE</u>	<u>REVENUES \$1000S</u>	<u>UNIT PRICE</u>	<u>REVENUES \$1000S</u>
<u>CUSTOMER CHARGE:</u>	<u>BILLS</u>	<u>\$/month</u>		<u>\$/month</u>	
1 PHASE - Regular	193,448	20.00	\$3,869.0	35.00	\$6,770.7
3 PHASE - Regular	114,100	45.00	\$5,134.5	60.00	\$6,846.0
SUBTOTAL	307,548		\$9,003.5		\$13,616.7
<u>ENERGY CHARGE:</u>	<u>(MWH)</u>	<u>¢/kWh</u>		<u>¢/kWh</u>	
G: Regular NON-DEMAND	377,500	11.1570	\$42,117.7	16.2616	\$61,387.5
SUBTOTAL	377,500		\$42,117.7		\$61,387.5
<u>ADJUSTMENTS</u>		<u>Rate</u>		<u>Rate</u>	
FUEL OIL ADJUSTMENT:		5.414 ¢/KWH	\$20,437.9	- ¢/KWH	\$0.0
RATE ADJUSTMENT (AES REFUND):		(0.400) (%)	(\$204.8)	- (%)	\$0.0
MISCELLANEOUS **			\$74.7		(\$34.7)
SUBTOTAL			\$20,307.8		(\$34.7)
TOTAL REVENUES			\$71,429.0		\$74,969.5

\*\* INCLUDES Schedule E Adj., Service Voltage Adj., Minimum Bill Adjustments, and TOU-C Option 1 Adjustment.

HAWAIIAN ELECTRIC COMPANY, INC.  
Docket No. 04-0113, Test-Year 2005  
Schedule J - General Service Demand

Estimate of Test Year Revenues

	PRESENT RATES			PROPOSED RATES		
	BILLING UNITS	UNIT PRICE	REVENUES \$000s	BILLING UNITS	UNIT PRICE	REVENUES \$000s
<u>ENERGY CHARGE:</u>	<u>(MWH)</u>	<u>¢/kWh</u>		<u>(MWH)</u>	<u>¢/kWh</u>	
0 - 200 KWH/KW	1,164,831	8.6900	\$101,223.8	1,206,650	13.6400	\$164,587.1
201 - 400 KWH/KW	674,369	7.5419	\$50,860.2	638,667	12.4919	\$79,781.6
> 400 KWH/KW	173,800	6.5130	\$11,319.6	167,683	11.4629	\$19,221.3
TOTAL	2,013,000		\$163,403.6	2,013,000		\$263,590.0
<u>DEMAND CHARGE:</u>	<u>kW</u>	<u>\$/kW</u>		<u>kW</u>	<u>\$/kW</u>	
ALL BILLING KW	6,471,648	5.75	\$37,212.0	6,741,296	8.50	\$57,301.0
<u>CUSTOMER CHARGE:</u>	<u>BILLS</u>	<u>\$/month</u>		<u>BILLS</u>	<u>\$/month</u>	
1 PHASE	6,629	35.00	\$232.0	6,629	50.00	\$331.5
3 PHASE	73,531	60.00	\$4,411.9	73,531	70.00	\$5,147.2
SUBTOTAL	80,160		\$4,643.9	80,160		\$5,478.7
ADJUSTMENTS:						
MISCELLANEOUS **			(\$1,988.3)			(\$2,968.4)
Fuel Oil Adjustment	¢/kWh	5.414	\$108,983.8	-		\$0.0
Rate Adjustment (AES Refund)	%	-0.400%	(\$813.1)	-		\$0.0
TOTAL REVENUE			\$311,441.9			\$323,401.3

\*\* INCLUDES Schedule E Adjustment, Service Voltage Adjustments, Power Factor Adjustment, Network Adjustment, TOU-C Option 2 Adjustment, and Rider Adjustments.

HAWAIIAN ELECTRIC COMPANY, INC.  
Docket No. 04-0113, Test-Year 2005  
SCHEDULE H - COMMERCIAL COOKING, HEATING, AIR  
CONDITIONING AND REFRIGERATION SERVICE

ESTIMATE OF TEST YEAR REVENUES

	<u>PRESENT RATES</u>			<u>PROPOSED RATES</u>	
	<u>BILLING UNITS</u>	<u>UNIT PRICE</u>	<u>REVENUES \$1000S</u>	<u>UNIT PRICE</u>	<u>REVENUES \$1000S</u>
	<u>MWH</u>	<u>¢/kWh</u>		<u>¢/kWh</u>	
<u>ENERGY CHARGE:</u>	53,400	7.7422	\$4,134.3	13.8583	\$7,400.3
	<u>kW</u>	<u>\$/kW</u>		<u>\$/KW</u>	
<u>DEMAND CHARGE:</u>	106,419	9.00	\$957.8	9.00	\$957.8
<u>CUSTOMER CHARGE:</u>	<u>BILLS</u>	<u>\$/month</u>		<u>\$/month</u>	
1 PHASE	3,989	20.00	\$79.8	25.00	\$99.7
3 PHASE	<u>8,515</u>	<u>45.00</u>	<u>\$383.2</u>	<u>60.00</u>	<u>\$510.9</u>
SUBTOTAL	12,504		\$463.0		\$610.6
ADJUSTMENTS		<u>Rate</u>		<u>Rate</u>	
FUEL OIL ADJUSTMEN		5.414 ¢/KWH	\$2,891.1	- ¢/KWH	\$0.0
RATE ADJUSTMENT (AES REFUND):		(0.400) (%)	(\$22.2)	- (%)	\$0.0
MISCELLANEOUS **			<u>\$0.0</u>		<u>(\$6.4)</u>
TOTAL REVENUES			\$8,424.0		\$8,962.3

\*\* INCLUDES Schedule E Adjustment.

HAWAIIAN ELECTRIC COMPANY, INC.  
SCHEDULE PS - LARGE POWER SECONDARY VOLTAGE SERVICE  
DOCKET NO. 04-0113 TEST-YEAR: 2005

ESTIMATE OF TEST YEAR REVENUES

	<u>PRESENT RATES</u>			<u>PROPOSED RATES</u>	
	<u>BILLING</u> <u>UNITS</u>	<u>UNIT PRICE</u>	<u>REVENUES</u> <u>\$1000S</u>	<u>UNIT PRICE</u>	<u>REVENUES</u> <u>\$1000S</u>
<u>ENERGY CHARGE:</u>	<u>(MWH)</u>	<u>¢/kWh</u>		<u>¢/kWh</u>	
0 - 200 KWH/KW	370,793	7.2087	\$26,729.4	11.9578	\$44,338.7
201 - 400 KWH/KW	340,776	6.4104	\$21,845.1	11.1595	\$38,028.9
> 400 KWH/KW	<u>163,563</u>	<u>6.1010</u>	<u>\$9,979.0</u>	<u>10.8503</u>	<u>\$17,747.1</u>
SUBTOTAL	875,132		\$58,553.5		\$100,114.7
<u>DEMAND CHARGE:</u>	<u>(kW)</u>	<u>\$/kW</u>		<u>\$/kW</u>	
0 - 500 KW	1,044,370	10.00	\$10,443.7	16.35	\$17,075.4
501 - 1500 KW	563,395	9.50	\$5,352.3	15.85	\$8,929.8
> 1500 KW	<u>300,108</u>	<u>8.50</u>	<u>\$2,550.9</u>	<u>14.85</u>	<u>\$4,456.6</u>
SUBTOTAL	1,907,873		\$18,346.9		\$30,461.8
	<u>BILLS</u>	<u>\$/month</u>		<u>\$/month</u>	
<u>CUSTOMER CHARGE:</u>	2,281	320.00	\$729.9	350.00	\$798.4
<u>ADJUSTMENTS:</u>					
MISCELLANEOUS **			(\$655.8)		(\$1,180.0)
Fuel Oil Adjustment	¢/kWh	5.414	\$47,379.6	-	\$0.0
Rate Adjustment (AES Refund)	%	-0.400%	(\$307.9)	-	\$0.0
TOTAL REVENUE			<u>\$124,046.2</u>		<u>\$130,194.9</u>

\*\* INCLUDES Schedule E Adj., Power Factor Adj., Network Adj., and Rider Adjustments.

HAWAIIAN ELECTRIC COMPANY, INC.  
SCHEDULE PP - LARGE POWER PRIMARY VOLTAGE SERVICE  
DOCKET NO. 04-0113 TEST-YEAR: 2005

ESTIMATE OF TEST YEAR REVENUES

	<u>PRESENT RATES</u>			<u>PROPOSED RATES</u>	
	<u>BILLING</u> <u>UNITS</u>	<u>UNIT PRICE</u>	<u>REVENUES</u> <u>\$1000S</u>	<u>UNIT PRICE</u>	<u>REVENUES</u> <u>\$1000S</u>
<u>ENERGY CHARGE:</u>	<u>(MWH)</u>	<u>¢/kWh</u>		<u>¢/kWh</u>	
0 - 200 KWH/KW	808,210	7.0715	\$57,152.6	11.9604	\$96,665.1
201 - 400 KWH/KW	748,793	6.2884	\$47,087.1	11.1772	\$83,694.1
> 400 KWH/KW	<u>611,525</u>	<u>5.9849</u>	<u>\$36,599.2</u>	<u>10.8737</u>	<u>\$66,495.4</u>
SUBTOTAL	2,168,528		\$140,838.9		\$246,854.6
<u>DEMAND CHARGE:</u>	<u>(kW)</u>	<u>\$/kW</u>		<u>\$/kW</u>	
0 - 500 KW	953,027	9.81	\$9,349.2	16.15	\$15,391.4
501 - 1500 KW	959,481	9.32	\$8,942.4	15.65	\$15,015.9
> 1500 KW	<u>2,390,098</u>	<u>8.34</u>	<u>\$19,933.4</u>	<u>14.65</u>	<u>\$35,014.9</u>
SUBTOTAL	4,302,606		\$38,225.0		\$65,422.2
	<u>BILLS</u>	<u>\$/month</u>		<u>\$/month</u>	
<u>CUSTOMER CHARGE:</u>	1,991	320.00	\$637.1	400.00	\$796.4
<u>ADJUSTMENTS:</u>	<u>(MWH)</u>	<u>¢/kWh</u>		<u>¢/kWh</u>	
MISCELLANEOUS **			(\$2,864.4)		(\$4,990.0)
Fuel Oil Adjustment	¢/kWh	5.414	\$117,404.1	-	\$0.0
Rate Adjustment (AES Refund)	%	-0.400%	(\$707.3)	-	\$0.0
TOTAL REVENUE			<u>\$293,533.4</u>		<u>\$308,083.2</u>

\*\* INCLUDES Schedule E Adj., Power Factor Adj., Secondary Metering Adj., and Rider Adjustments.

HAWAIIAN ELECTRIC COMPANY, INC.  
SCHEDULE PT - LARGE POWER TRANSMISSION VOLTAGE SERVICE  
DOCKET NO. 04-0113 TEST-YEAR: 2005

ESTIMATE OF TEST-YEAR REVENUES

	<u>PRESENT RATES</u>			<u>PROPOSED RATES</u>	
	<u>BILLING UNITS</u>	<u>UNIT PRICE</u>	<u>REVENUES \$1000S</u>	<u>UNIT PRICE</u>	<u>REVENUES \$1000S</u>
<u>ENERGY CHARGE:</u>	<u>(MWH)</u>	<u>¢/kWH</u>		<u>¢/kWH</u>	
0 - 200 KWH/KW	63,629	6.9708	\$4,435.5	11.7511	\$7,477.1
201 - 400 KWH/KW	62,717	6.1989	\$3,887.8	10.9792	\$6,885.8
> 400 KWH/KW	<u>47,394</u>	<u>5.8997</u>	<u>\$2,796.1</u>	<u>10.6800</u>	<u>\$5,061.7</u>
SUBTOTAL	173,740		\$11,119.4		\$19,424.6
<u>DEMAND CHARGE:</u>	<u>(kW)</u>	<u>\$/kW</u>		<u>\$/kW</u>	
0 - 500 KW	24,003	9.67	\$232.1	16.00	\$384.0
501 - 1500 KW	48,006	9.19	\$441.2	15.50	\$744.1
> 1500 KW	<u>246,335</u>	<u>8.22</u>	<u>\$2,024.9</u>	<u>14.50</u>	<u>\$3,571.9</u>
SUBTOTAL	318,344		\$2,698.2		\$4,700.0
	<u>BILLS</u>	<u>\$/month</u>		<u>\$/month</u>	
<u>CUSTOMER CHARGE:</u>	48	320.00	\$15.4	400.00	\$19.2
<u>ADJUSTMENTS:</u>					
MISCELLANEOUS **			(\$82.9)		(\$155.3)
Fuel Oil Adjustment	¢/kWH	5.414	\$9,406.3	-	\$0.0
Rate Adjustment (AES Refund):	%	-0.400%	<u>(\$55.0)</u>	-	<u>\$0.0</u>
TOTAL REVENUES			\$23,101.4		\$23,988.5

\*\* INCLUDES Schedule E Adj., Power Factor Adj., Secondary Metering Adj.

HAWAIIAN ELECTRIC COMPANY, INC.  
Docket No. 04-0113, Test-Year 2005  
SCHEDULE F - PUBLIC STREET LIGHTING SERVICE  
HIGHWAY LIGHTING, & PARK & PLAYGROUND FLOODLIGHTING

ESTIMATE OF TEST-YEAR REVENUES

	<u>PRESENT RATES</u>			<u>PROPOSED RATES</u>	
	<u>BILLING UNITS</u>	<u>UNIT PRICE</u>	<u>REVENUES \$1000S</u>	<u>UNIT PRICE</u>	<u>REVENUES \$1000S</u>
<u>CUSTOMER CHARGE:</u>	<u>Bills</u>	<u>\$/month</u>		<u>\$/month</u>	
Customers	4,872	0.00	\$0.0	20.00	\$97.4
<u>ENERGY CHARGE:</u>	<u>MWH</u>	<u>¢/kWh</u>		<u>¢/kWh</u>	
0 - 150 KWH/KW	18,619	12.7049	\$2,365.5	18.8659	\$3,512.6
> 150 KWH/KW	21,681	8.7309	\$1,892.9	14.8920	\$3,228.7
SUBTOTAL	<u>40,300</u>		<u>\$4,258.4</u>		<u>\$6,741.3</u>
<u>ADJUSTMENTS:</u>					
MISCELLANEOUS **			\$14.1		\$9.8
FUEL OIL ADJUSTMENT:		5.414 ¢/kWh	\$2,181.8	- ¢/kWh	\$0.0
RATE ADJUSTMENT (AES REFUND):		(0.400) (%)	(\$17.1)	- (%)	\$0.0
TOTAL REVENUES			<u>\$6,437.2</u>		<u>\$6,848.5</u>

\*\* INCLUDES Schedule E Adj., Minimum Bill Adj., Secondary Metering Adj.

HAWAIIAN ELECTRIC COMPANY, INC.  
DOCKET NO. 04-0113  
TEST YEAR 2005 REBUTTAL

ELECTRIC REVENUE  
COMPARISON OF DIRECT TESTIMONY AND REBUTTAL TESTIMONY ESTIMATES  
AT PRESENT RATES

Rate Class	Direct Testimony (\$000s)	Rebuttal Testimony (\$000s)	Difference (\$000s)	Change (%)
Schedule R	\$317,901.1	\$379,853.7	\$61,952.6	19.49%
Schedule G	\$60,702.9	\$71,429.0	\$10,726.1	17.67%
Schedule J	\$255,035.3	\$311,441.9	\$56,406.6	22.12%
Schedule H	\$6,913.7	\$8,424.0	\$1,510.3	21.85%
Schedule PS	\$99,113.9	\$124,046.2	\$24,932.3	25.16%
Schedule PP	\$230,924.5	\$293,533.4	\$62,608.9	27.11%
Schedule PT	\$18,142.7	\$23,101.4	\$4,958.7	27.33%
Schedule F	\$5,298.0	\$6,437.2	\$1,139.2	21.50%
TOTAL	\$884,028.4	\$1,136,826.2	\$252,797.8	28.59%

**HAWAIIAN ELECTRIC COMPANY, INC.  
DOCKET NO. 04-0113  
TEST YEAR 2005 REBUTTAL**

**TOTAL NEW RIDER CUSTOMERS SINCE LAST RATE CASE  
RIDER I, RIDER M, RIDER T, SCHEDULE U  
1996-2005<sup>1</sup>**

<u>Year</u>	<u>New Rider Customers</u>	<u>Cumulative New Riders</u>
1996	6	6
1997	3	9
1998	2	11
1999	3	14
2000	1	15
2001	4	19
2002	1	20
2003	7	27
2004	3	30
<u>2005</u>	<u>1</u>	<u>31</u>
<u><u>TOTAL</u></u>	<u><u>31</u></u>	

<sup>1</sup> As of July 31, 2005

**HAWAIIAN ELECTRIC COMPANY, INC.  
DOCKET NO. 04-0113  
2005 TEST YEAR REBUTTAL**

**DERIVATION OF RATE ADJUSTMENT  
FOR CALCULATION OF ELECTRIC REVENUES  
AT PRESENT RATES**

L1	AES Hawaii Capacity Payment Adjustment	- \$2,904,000
L2	Revenue Tax Factor	1.0975
L3 = L1 x L2	Amount to be Refunded to Customers	- \$3,187,140
L4	Base Electric Revenues @ Present Rates, TY 2005	\$796,127,700
L5 = L3 ÷ L4	Rate Adjustment @ Present Rates, TY 2005	-0.400%

HAWAIIAN ELECTRIC COMPANY, INC.  
DOCKET NO. 04-0113  
TEST YEAR 2005 REBUTTAL

ELECTRIC REVENUE  
COMPARISON OF DIRECT TESTIMONY AND REBUTTAL TESTIMONY ESTIMATES  
AT PROPOSED RATES

Rate Class	Direct Testimony (\$000s)	Rebuttal Testimony (\$000s)	Difference (\$000s)	Change (%)
Schedule R	\$349,194.6	\$404,126.4	\$54,931.8	15.73%
Schedule G	\$66,678.5	\$74,969.6	\$8,291.1	12.43%
Schedule J	\$280,140.5	\$323,401.3	\$43,260.8	15.44%
Schedule H	\$7,594.3	\$8,962.3	\$1,368.0	18.01%
Schedule PS	\$108,870.7	\$130,194.9	\$21,324.2	19.59%
Schedule PP	\$253,656.2	\$308,083.3	\$54,427.1	21.46%
Schedule PT	\$19,928.7	\$23,988.5	\$4,059.8	20.37%
Schedule F	\$5,819.5	\$6,848.5	\$1,029.0	17.68%
Total Electric Revenue	<u>\$1,091,883.0</u>	<u>\$1,280,574.8</u>	<u>\$188,691.8</u>	<u>17.28%</u>

**HAWAIIAN ELECTRIC COMPANY, INC.**  
**DOCKET NO. 04-0113**  
**2005 TEST YEAR REBUTTAL**

**OTHER OPERATING REVENUES**

(\$ Thousands)

	<u>At Present Rates</u>	<u>At Proposed Rates</u>	<u>Proposed Increase</u>	<u>% Increase</u>
Non-Sales Electric Utility Charges				
Service Establishment Charges	\$828.7	\$1,216.9	\$388.2	47%
Late Payment Charges	1,218.3	1,280.6	62.3	5%
Field Collection Charges	99.6	332.2	232.6	234%
Payment Protection Program (net)	93.6	93.6	0.0	0%
Returned Check Charges	37.8	82.2	44.4	117%
Late Payment Charges - OCARS	10.0	10.0	0.0	0%
Purch. Pwr. Metering Charges	<u>0.6</u>	<u>0.6</u>	<u>0.0</u>	<u>0%</u>
Subtotal	\$2,288.6	\$3,016.1	\$727.5	37%
Miscellaneous Revenues				
Amort. Gain on Land Sale	\$368.4	\$368.4	\$0.0	0%
Rent – Electric Property	685.0	685.0	0.0	0%
Other	<u>(7.0)</u>	<u>(7.0)</u>	<u>0.0</u>	<u>0%</u>
Subtotal	\$1,046.4	\$1,046.4	\$0.0	0%
Total Other Operating Revs.	\$3,335.0	\$4,062.5	\$727.5	22%

HAWAIIAN ELECTRIC COMPANY, INC.  
DOCKET NO. 04-0113  
2005 TEST YEAR REBUTTAL

OTHER OPERATING REVENUES  
COMPARISON OF DIRECT TESTIMONY AND REBUTTAL ESTIMATES  
AT PRESENT RATES  
(\$ Thousands)

	Direct Testimony	Rebuttal Testimony	Difference \$	% Difference
Service Establishment Charges	\$828.7	\$828.7	\$ 0.0	0%
Late Payment Charges	994.0	1,218.3	224.3	23%
Field Collection Charges	99.6	99.6	0.0	0%
Payment Protection Program (net)	93.6	93.6	0.0	0%
Returned Check Charges	37.8	37.8	0.0	0%
Late Payment Charges - OCARS	10.0	10.0	0.0	0%
Purch. Pwr. Metering Charges	<u>0.6</u>	<u>0.6</u>	<u>0.0</u>	<u>0%</u>
Subtotal	\$2,064.3	\$2,288.6	\$224.3	11%
Miscellaneous Revenues				

**HAWAIIAN ELECTRIC COMPANY, INC.  
DOCKET NO. 04-0113  
2005 TEST YEAR REBUTTAL**

**OTHER OPERATING REVENUES  
COMPARISON OF DIRECT TESTIMONY AND REBUTTAL ESTIMATES  
AT PROPOSED RATES  
(\$ Thousands)**

	<u>Direct Testimony</u>	<u>Rebuttal Testimony</u>	<u>Difference \$</u>	<u>% Difference</u>
Non-Sales Electric Utility Charges				
Service Establishment Charges	\$1,216.9	\$1,216.9	\$ 0.0	0%
Late Payment Charges	1,091.9	1,280.6	188.7	17%
Field Collection Charges	332.2	332.2	0.0	0%
Payment Protection Program (net)	93.6	93.6	0.0	0%
Returned Check Charges	82.2	82.2	0.0	0%
Late Payment Charges - OCARS	10.0	10.0	0.0	0%
Purch. Pwr. Metering Charges	<u>0.6</u>	<u>0.6</u>	<u>0.0</u>	<u>0%</u>
Subtotal	\$2,827.4	\$3,016.1	\$188.7	7%
Miscellaneous Revenues				
Amort. Gain on Land Sale	\$333.0	\$368.4	\$35.4	11%
Rent – Electric Property	684.9	685.0	0.1	0%
Other	<u>(7.0)</u>	<u>(7.0)</u>	<u>0.0</u>	<u>0%</u>
Subtotal	\$1,010.9	\$1,046.4	\$35.5	4%
Total Other Operating Revs.	\$3,838.3	\$4,062.5	\$224.2	6%

HAWAIIAN ELECTRIC COMPANY, INC.  
DOCKET NO. 04-0113  
TEST YEAR 2005 REBUTTAL

TOTAL OPERATING REVENUE  
COMPARISON OF REBUTTAL TESTIMONY AND CA AND DOD POSITIONS  
AT PRESENT RATES  
In \$000s

Revenue	HECO Rebuttal <sup>1</sup> (\$000s) A	CA Testimony <sup>2</sup> (\$000s) B	DOD Testimony <sup>3</sup> (\$000s) C	CA Difference (\$000s) D = B - A	DOD Difference (\$000s) E = C - A	CA Difference (%) F = D + A	DOD Difference (%) G = E + A
Electric Revenue	\$1,218,267	\$1,248,037	\$1,248,172	\$29,770	\$29,905	2.4%	2.5%
Other Operating Revenue	\$3,335	\$3,105	\$3,110	(\$230)	(\$225)	-6.9%	-6.7%
Total Operating Revenue	\$1,221,602	\$1,251,142	\$1,251,282	\$29,540	\$29,680	2.4%	2.4%

<sup>1</sup> Source: HECO-R-301 and HECO-R-307.

<sup>2</sup> Source: CA-500.

<sup>3</sup> Source: DOD-104.

HAWAIIAN ELECTRIC COMPANY, INC.  
DOCKET NO. 04-0113  
TEST YEAR 2005 REBUTTAL

TOTAL OPERATING REVENUE  
COMPARISON OF REBUTTAL TESTIMONY AND CA AND DOD POSITIONS  
AT PROPOSED RATES  
In \$000s

Revenue	HECO Rebuttal <sup>1</sup> (\$000s) A	CA Testimony <sup>2</sup> (\$000s) B	DOD Testimony <sup>3</sup> (\$000s) C	CA Difference (\$000s) D = B - A	DOD Difference (\$000s) E = C - A	CA Difference (%) F = D + A	DOD Difference (%) G = E + A
Electric Revenue	\$1,280,575	\$1,271,513	\$1,267,482	(\$9,062)	(\$13,093)	-0.7%	-1.0%
Other Operating Revenue	\$4,063	\$3,105	\$3,110	(\$958)	(\$953)	-23.6%	-23.4%
Total Operating Revenue	\$1,284,637	\$1,274,618	\$1,270,592	(\$10,019)	(\$14,045)	-0.8%	-1.1%

<sup>1</sup> Source: HECO-R-301 and HECO-R-307.

<sup>2</sup> Source: CA-500 and CA-101.

<sup>3</sup> Source: DOD-104 and DOD-101.

REBUTTAL TESTIMONY OF

ROSS H. SAKUDA, P.E.

DIRECTOR  
GENERATION PLANNING DIVISION  
POWER SUPPLY PLANNING AND ENGINEERING DEPARTMENT  
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Fuel Expense,  
Excluded Expenses

INTRODUCTION

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15  
16  
17  
18  
19  
20  
21

Q. Please state your name and business address.

A. My name is Ross Sakuda. I am the Director of the Generation Planning Division in the Power Supply Services Department. My business address is 820 Ward Avenue, Honolulu, Hawaii.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted written testimony, exhibits and supporting workpapers as HECO T-4.

Q. What is the scope of your rebuttal testimony?

A. My rebuttal testimony will:

- 1) provide updated 2005 test year estimates for fuel oil expense, fuel-related expense, the generation efficiency factor, and fuel inventory;
- 2) provide an update on HECO's capacity situation;
- 3) describe the adjustments made in the production simulation and address differences in assumptions used by HECO and the Consumer Advocate ("CA") in the respective production simulations;
- 4) address issues raised by the CA in their direct testimony, including (a) the calibration factor; (b) the production simulation input files submitted to the CA in response to their request; and (c) the general practice with regard to updated information for production simulation results; and
- 5) provide HECO's assessment of the Department of Defense's ("DOD's)

estimates of test year fuel oil expenses, fuel related expenses, and fuel inventory in their direct testimony.

UPDATED 2005 TEST YEAR ESTIMATES

Q. What are the updated normalized 2005 test year estimates for the items in your

1 area of responsibility?

2 A. The updated normalized test year estimates in my area of responsibility are:

3	<u>Test Year 2005</u>		<u>Units</u>
4	1) Fuel Expense	449,447,000	\$
5	a) Fuel Expense (Oil)	444,802,000	\$
6	b) Fuel-Related Expense	4,645,000	\$
7			
8	2) Fuel Price		
9	a) Low Sulfur Fuel Oil	53.7346	\$/BBL
10	b) Diesel	79.4392	\$/BBL
11	3) Purchased Energy Forecast	3,426.3	GWh
12	4) Efficiency Factor (Sales Heat Rate)	0.011140	MMBtu/kWh
13			SALES
14	5) Fuel Inventory	44,484,000	\$

15 Q. Which exhibits and workpapers provide the details of these test year estimates?

16 A. The exhibits that provide the details for these test year estimates can be found on  
17 HECO-R-401 to 404 for fuel oil expenses, HECO-R-405 for fuel related expenses,  
18 HECO-R-406 for test year fuel efficiency, and HECO-R-408 and 409, page 1, for  
19 fuel oil inventory. The exhibits reference the appropriate workpapers that contain  
20 the detailed calculations of the test year estimates.

21 Q. How were the updated normalized 2005 test year estimates for fuel oil expense,  
22 fuel related expense, fuel inventory, purchased energy forecast and efficiency  
23 factor determined?

24 A. The updated normalized 2005 test year estimates for these items were determined  
25 by performing a computer production simulation for the test year using updated  
26 inputs that were provided (to the extent they were available) in HECO's May 5,  
27 2005 transmittal to the CA and DOD ("May 5<sup>th</sup> transmittal") and other updated

1 inputs that are described later in my testimony.

2 Fuel Inventory

3 Q. What is the fuel inventory value of \$44,484,000 based on?

4 A. The fuel inventory value is based on a 35-day inventory of Low Sulfur Fuel Oil  
5 ("LSFO") as shown on HECO-R-409, page 1 (788,080 barrels); 25,509 barrels of  
6 central station diesel oil inventory based on a five-year (2000-2004) average as  
7 shown on HECO-R-411; and 500 barrels of diesel oil inventory for the distributed  
8 generation ("DG") units, which are discussed by Mr. Scott Seu in HECO RT-7;  
9 and the fuel prices shown on HECO-R-408.

10 Q. Did the CA agree with the 35-day inventory level for LSFO?

11 A. Yes. HECO submitted a Fuel Inventory Study (HECO-WP-409) as part of its  
12 direct testimony. The CA indicated in their direct testimony that they agree with  
13 HECO's stated goal of a 35-day inventory level. (See CA-T-3, page 54, lines 11  
14 to 13.) The CA further stated "The HECO inventory study is reasonable and  
15 recommends a LSFO inventory that is comparable (2 days less) to its actual  
16 inventory levels in the period 1999 to 2003." (See CA-T-3, page 55, lines 15 to  
17 17.) The CA also stated "I utilized the same 35-day supply of LSFO inventory for  
18 the purposes of determining the test year fuel inventory amounts." (See CA-T-3,  
19 page 57, lines 17 to 19.)

20 Q. Notwithstanding the agreement between HECO and the CA on the 35-day  
21 inventory level for LSFO, do HECO and the CA agree on the specific inventory  
22 amount in barrels?

23 A. No, they do not. I will discuss this later in my testimony where the DOD's  
24 estimates of LSFO inventory are covered.

25 Q. What is the CA's position with respect to the proposed 26,009 barrels of diesel oil

1 inventory for central station and DG inventory?

2 A. The CA apparently does not agree with this specific amount. However, the CA  
3 agrees that using a five-year average of historical diesel oil inventory plus an  
4 adjustment for DG diesel oil inventory is reasonable. But the CA did not use the  
5 most recent five-year average that HECO provided.

6 The 26,009 barrel amount was provided by HECO to the CA and DOD in its  
7 May 5<sup>th</sup> transmittal. This was based on the five-year (2000-2004) average diesel  
8 oil inventory plus a 500 barrel inventory amount for the DG units. (See  
9 Attachment 7 of that submittal.) In the CA's calculation of the diesel oil  
10 inventory value, they used a diesel oil inventory amount of 22,268 barrels, which  
11 is based on the five-year (1999-2003) average diesel oil inventory shown on  
12 HECO-411, plus a 500 barrel amount for the DG units. (See CA-308, line 2,  
13 column (g), and CA-T-3, page 56, lines 4 to 9.)

14 HECO's position is that the 26,009 barrel amount and the \$2,069,000 value  
15 as shown on HECO-R-408, line 2, should be used for diesel oil inventory.

16  
17 HECO'S CAPACITY SITUATION

18 Q. What is HECO's forecast for sales in the test year?

19 A. As Ms. Catherine Hazama indicates in HECO RT-2, sales for the test year are  
20 forecasted to be 7,856.0 GWh in the test year. This compares to test year sales of  
21 7,842.8 GWh used in direct testimony.

22 Q. Does HECO forecast that sales will continue to grow beyond the test year?

23 A. Yes, as I indicated in my direct testimony in HECO T-4 on page 2, HECO  
24 forecasts that both sales and peak demand will continue to grow in future years.

25 Q. What will be the impact of the growing demand on HECO's capacity situation?

1       A.   On March 20, 2005, HECO submitted to the Commission with a copy to the CA  
2       its Adequacy of Supply report ("2005 AOS report"). The report provided  
3       analyses that indicated that HECO has a reserve capacity shortfall. The report  
4       concluded that "HECO expects to have sufficient generation capacity to meet the  
5       forecasted peak demand of electricity use. However, HECO anticipates reserve  
6       capacity shortfalls in 2005 and projects these shortfalls to continue at least until  
7       2009, which is the earliest that HECO expects to be able to permit, acquire, install  
8       and place into commercial operation its next central station generating unit."<sup>1</sup>

9       Q.   In your direct testimony in HECO T-4, pages 3 to 6, you outlined HECO's plan to  
10      meet consumers' increasing need for electricity. Please provide a brief update on  
11      this plan.

12      A.   My direct testimony indicated that HECO plans to meet consumers' increasing  
13      need for electricity through a portfolio of energy solutions. The elements of this  
14      portfolio include: (1) maintaining and improving the availability of HECO's  
15      existing generation; (2) continuing HECO's existing energy efficiency DSM  
16      programs, with substantial enhancements and modifications; (3) implementing the  
17      Residential Direct Load Control and Commercial and Industrial Direct Load  
18      Control Programs; (4) installing utility-owned CHP systems; (5) implementing  
19      renewable energy projects to the extent economically viable; and (6) adding new  
20      generating capacity, including that from existing Independent Power Producers  
21      ("IPPs"). HECO provided the updated status of each of these elements in  
22      responses to the CA-IRs (e.g., CA-IR-295<sup>2</sup>, CA-IR-446<sup>3</sup>, CA-IR-558<sup>4</sup> and CA-IR-

---

<sup>1</sup> Page 27 of the report.

<sup>2</sup> Filed with the CA on March 11, 2005 and with the Department of Defense ("DOD") on March 16, 2005.

<sup>3</sup> Filed with the CA and DOD on June 8, 2005.

<sup>4</sup> Filed with the CA and DOD on June 8, 2005.

1 574<sup>5</sup> in the instant docket). In addition, the application for approval to expend  
2 funds for HECO's next generating unit, which is targeted for installation in 2009,  
3 was filed with the Commission on June 17, 2005. Updated information on the  
4 Demand-Side Management ("DSM") and Load Management Programs are  
5 provided by Mr. Alan Hee in HECO RT-10. Updated information on Distributed  
6 Generators to be installed at HECO sites is provided by Mr. Scott Seu in HECO  
7 RT-7.

8 Q. Do any of the updates on these elements affect the estimates of test year fuel oil  
9 expenses, fuel related expenses or fuel inventory?

10 A. Yes, one element of our portfolio of energy solutions has changed such it affects

11 ~~our estimates of test year fuel oil expenses, fuel related expenses and fuel~~



12 inventory. As explained in Attachment 1A of HECO's rate case updates (May 5<sup>th</sup>  
13 transmittal), HECO is removing combined heat and power ("CHP") project  
14 revenues, expenses, and rate base costs from its 2005 test year rate case. Also,  
15 HECO is adding to the test year rate case the capital costs and expenses associated  
16 with the installation, operation, and maintenance of nine distributed generation  
17 ("DG") units at HECO sites. These changes are covered in more detail by Mr.  
18 Scott Seu in HECO RT-7.

19 Q. How do these changes affect the estimates of test year fuel oil expenses, fuel  
20 related expenses or fuel inventory?

1 CHP units in the test year have been removed from total test year fuel oil  
2 expenses.

3 2) The cost of transporting the fuel for the CHP units has been removed from  
4 total test year fuel related expenses.

5 3) The fuel oil expenses that are projected to be incurred by the operation of  
6 the DG units at HECO sites were added to the total test year fuel oil  
7 expenses.

8 4) The cost of transporting the fuel for the DG units has been added to total test  
9 year fuel related expenses.

10 5) A diesel oil inventory amount of 500 barrels for the DG units is now  
11 included in the total diesel oil inventory.

12 Details of these changes are provided in Exhibits HECO-R-401, 402, 403, 404,  
13 405, 406, 408, 409, page 1, and 411.

14  
15 ADJUSTMENTS TO PRODUCTION SIMULATION

16 Q. What adjustments have been made in the production simulation in your rebuttal  
17 testimony?

18 A. Adjustments have been made in the production simulation to account for the  
19 following:

- 20 1) revised sales and peak forecast;  
21 2) updated fuel prices;  
22 3) updated generating unit "ABC" coefficients;  
23 4) updated no-charge energy;  
24 5) loss factor;  
25 6) updated fuel trucking expense;  
26 7) updated generating unit equivalent forced outage rates ("EFORs");

- 1           8)    updated spinning reserve requirement;  
2           9)    removal of CHP generation; and  
3           10)   addition of DG at HECO sites.

4           I will also discuss the maintenance schedule.

5       Q.    Did the CA prepare a production simulation to compare to HECO's results?

6       A.    Yes, the CA prepared an independent production simulation upon which they  
7           based their recommendations to the Commission that certain adjustments be  
8           made. (See CA-T-3, page 3, lines 19 to 21.)

9       Sales and Peak Forecast

10      Q.    What change was made to HECO's test year sales and peak forecast?

11      A.    HECO's rebuttal position is based on test year sales of 7,856.0 GWh and a test  
12           year peak of 1,321 MW (net-to-system). In direct testimony, the test year sales  
13           and peak were 7,842.8 GWh and 1,316 MW (net-to-system), respectively.

14      Q.    Why was this revision made?

---

15      A.    The revision was made to reflect (i) withdrawal of HECO's proposed Economic  
16           Development Rate as noted in response to CA-IR-235; (ii) the delay in HECO's  
17           proposed CHP Program as noted in response to CA-IR-276, part b; and (iii) the  
18           impact of only the continuation of the existing Demand-Side Management  
19           ("DSM") programs. The updated sales forecast was provided in the May 5<sup>th</sup>  
20           transmittal. The forecast is further described by Ms. Catherine Hazama in HECO  
21           RT-2.

22      Q.    What was the CA's position with respect to the sales and peak forecast that should

1 page 10, lines 19 to 21.)

2

3 Fuel Prices

4 Q. What are the updated fuel prices used in the rebuttal testimony?

5 A. The updated fuel prices are as follows:

6 Low Sulfur Fuel Oil 53.7346 \$/BBL

7 Diesel 79.4392 \$/BBL

8 These reflect actual May 2005 fuel oil prices. (See HECO-R-402.) These prices  
9 were provided in HECO's May 5<sup>th</sup> transmittal in Attachment 1B.

10 Q. Why were the fuel prices updated?

11 A. The updated prices reflect recent information. These prices were the latest  
12 available at the time the production simulation for rebuttal testimony was  
13 prepared.

14 Q. What fuel prices were used in HECO's direct testimony?

15 A. The fuel prices used in direct testimony were based on May 2004 prices and were  
16 as follows:

17 Low Sulfur Fuel Oil 34.7257 \$/BBL

18 Diesel 56.8000 \$/BBL

19 Q. What is the CA's position with respect to which fuel prices should be used.

20 A. The CA used HECO's May 2005 updated fuel prices. (See CA-T-3, page 4, lines  
21 18 and 19.)

22 Generating Unit "ABC" Coefficients

23 Q. What are generating unit "ABC" coefficients?

24 A. Generating unit ABC coefficients are three separate values that are coefficients in

1 between fuel consumption and the load on a generating unit. The fuel  
2 consumption rate on a generating unit can be represented by the equation:

3 
$$\text{Fuel Consumption Rate} = A + (B \times L) + C \times L^2$$

4 where L is the load on the unit and A, B and C are the three coefficients in the  
5 equation. Each generating unit has a particular relationship between load and fuel  
6 consumption rate and therefore, each generating unit has a particular set of ABC  
7 coefficients used to calculate fuel consumption rates at various loads. The fuel  
8 consumption rate, in Btu per hour, when divided by the load, in kW, is called the  
9 heat rate, in Btu/kWh.

10 Q. Which set of ABC coefficients did HECO use in its production simulation for its  
11 rebuttal testimony?

12 A. HECO used the set of revised ABC coefficients that were provided in response to  
13 CA-IR-128 (supplemented on May 2, 2005). These ABC coefficients reflect more  
14 recently available information.

15 Q. Which set of ABC coefficients did the CA use in its production simulation for its  
16 direct testimony?

17 A. The CA used the updated set of revised ABC coefficients (i.e., those provided by  
18 HECO in response to CA-IR-128 (supplemented on May 2, 2005)). (See CA-T-3,  
19 page 34, lines 1 to 3.) In other words, the CA used the same set of ABC  
20 coefficients in its production simulation as HECO did in its production simulation  
21 for rebuttal testimony.

22 No-Charge Energy

23 Q. What is No-Charge Energy?

24 A. No-Charge Energy includes electric energy use at HECO's buildings and facilities  
25 as well as energy that is unaccounted for (e.g., theft). It does not include

1 consumption at the generating stations by auxiliary equipment.

2 Q. What amount of No-Charge Energy did HECO use in its direct testimony?

3 A. HECO used 16.6 GWh in its direct testimony. This was based on a five-year  
4 average of 0.212% of sales.

5 Q. What is the CA's position on this issue?

6 A. The CA estimates that No-Charge energy should be 15.5 GWh for the purposes of  
7 this proceeding, based on the average of 2000 to 2004 recorded Company use.  
8 (See CA-T-3, page 11, line 4, to page 15, line 14, and CA-303, line 2, column  
9 (d).) However, HECO has discovered an error in the 2003 value for Company  
10 Use that it provided in response to CA-IR-153. The 2003 Company Use energy  
11 should be 15,001,635 kWh, instead of the 15,379,093 kWh. Therefore, the  
12 ~~calculated five year average~~ should be 15.4 GWh as provided in the table below

13	<u>Year</u>	<u>Company Use (kWh)</u>
14	2000	15,514,884
15	2001	15,541,140
16	2002	15,379,093
17	2003	15,001,635
18	2004	15,520,824

1 be a good indication of future use. Special adjustments may need to be made to  
2 recorded values to reflect anomalous situations or an adjustment may need to be  
3 made to account for new facilities that will be added to the system.

4 Loss Factor

5 Q. What are loss factors?

6 A. Loss factors represent the amount of energy lost as heat during the transformation  
7 of voltage and transmission and distribution of power from the point of injection  
8 into the electrical grid to the customers' meters. The amount of energy lost.

---

---

9 expressed as a percentage of the total amount of energy injected into the grid, is  
10 the loss factor.

11 Q. What loss factor did HECO use in its production simulation for its direct  
12 testimony?

13 A. HECO used a loss factor of 4.70%. This was based on an analysis of losses  
14 through the system transformers, transmission system and distribution system.  
15 (See HECO-403 and HECO-WP-403, page 2.)

16 Q. What loss factor did the CA use in its production simulation?

17 A. The CA used a loss factor of 4.65%. This was based on a five-year average (2000  
18 to 2004) of recorded system losses. (See CA-T-3, page 19, lines 14 and 15.)

19 Q. Does HECO agree with the CA's position on the loss factor?

20 A. While HECO does not agree with the CA's method used to derive the CA's  
21 proposed loss factor, in order to limit the number of outstanding issues, for the  
22 purposes of this proceeding, HECO will use the five-year (2000-2004) average of  
23 recorded losses as the estimate of losses in the test year. HECO will use a value  
24 of 383.9 GWh, which is the same value used by the CA in their direct testimony.  
25 (See CA-303, line 4.) HECO does not agree that a five-year average of historical

1 system losses should be used in all future rate case proceedings. Consideration  
2 needs to be given to specific circumstances which are anticipated to occur and

3 which may affect the amount of losses. For example, if in future years there is  
4 expected to be a higher level of unavailability in the generating units closer to the

1 reason is that they are incorrectly using the \$2.9053/barrel trucking cost for the  
2 LSFO for the Honolulu Power Plant that appears on HECO's response to CA-IR-  
3 137, revised, page 3. This per barrel trucking cost was determined based on  
4 trucking 132,246 barrels of LSFO, as shown on HECO-405, page 2, line 1,  
5 column (A), and in HECO's response to CA-IR-137 (revised), page 2. However,  
6 this per barrel trucking cost is sensitive to the number of barrels consumed at the  
7 Honolulu Power Plant because the cost is based on a three-tiered price structure as  
8 discussed in HECO's response to CA-IR-137. HECO is using a per barrel  
9 trucking cost of \$2.4665/barrel based on the 245,301 barrels of consumption at the  
10 Honolulu Power Plant, as shown on HECO-R-405, page 2, line 1.

11 The second reason the CA's estimate of LSFO trucking cost is higher is that  
12 they are using a higher number of barrels of LSFO that must be trucked to Iwilei.  
13 They are using 246,884 barrels (as shown on CA-IR-305, page 2, line 1, column  
14 (g)) compared to HECO's estimate of 245,301 barrels.

15 Q. What is HECO's position on the LSFO trucking cost?

16 A. HECO is using its lower estimate of \$605,000 as the estimated test year LSFO  
17 trucking expenses.

18 Q. Why is the CA's estimate of DG diesel oil trucking cost (\$3,000) lower than  
19 HECO's estimate (\$55,000)?

20 A. The CA estimates that the DGs will generate only 1.5 GWh in the test year (see  
21 CA-306, line 5, column (c)) and consume only 2,480 barrels of diesel (see CA-  
22 305, page 3, line 8, column (g)). This compares to HECO's estimates of 7.4 GWh  
23 of DG energy generation (HECO-R-403, page 1, line 7b) and 12,384 barrels of  
24 diesel oil consumption (HECO-R-405, line 8, column (A)).

25 Q. Why is the CA's estimate of DG unit energy generation significantly lower than

1 HECO's estimate?

2 A. The CA's estimate of DG unit energy production in the test year was calculated as  
3 follows:

4  $(1.64 \text{ MW per DG unit}) \times (3 \text{ units per site}) \times (3 \text{ sites}) \times (5 \text{ hours per day}$   
5  $\text{operation}) \times (20 \text{ days of operation in the test year}) = 1,476 \text{ MWh}$

6 (See CA's response to HECO/CA-IR-306, part b.) The CA calculates 2,480  
7 barrels of diesel oil consumption for this amount of energy production. The CA  
8 applied a trucking cost of \$1.3524 per barrel to arrive at a DG diesel oil trucking  
9 expense of about \$3,000. (See CA-305, page 2, line 8, columns (h) and (i).)

10 HECO's estimate of DG unit energy production was based on a normalized  
11 year. HECO estimates that the DG units, once installed, would operate about 100  
12 hours in July, 100 hours in August, 200 hours in September, and 100 hours in  
13 October each year. (See May 5<sup>th</sup> transmittal, Attachment 1A, page 5.) HECO's  
14 estimate of DG unit energy production in the test year was calculated as follows:  
15  $(1.64 \text{ MW per DG unit}) \times (3 \text{ units per site}) \times (3 \text{ sites}) \times (500 \text{ hours per year}) =$   
16  $7,380 \text{ MWh}$ . HECO applied a trucking cost of \$4.41 per barrel to arrive at a DG  
17 diesel oil trucking expense of \$55,000. (See HECO-R-405, page 2, line 8,  
18 columns (B) and (C).)

19 Q. What is HECO's position on DG unit fuel trucking expense?

20 A. HECO's position is that it is reasonable to calculate DG unit energy production  
21 and diesel oil consumption on a normalized basis. HECO's position is also that  
22 the CA used an incorrect diesel oil trucking cost (\$1.3524 per barrel). Therefore,  
23 HECO's position is that its estimate of \$55,000 for DG diesel oil trucking expense  
24 should be used for this proceeding. Mr. Scott Seu (HECO RT-7) further discusses  
25 this subject.

1     Equivalent Forced Outage Rates

2     Q.   Which set of Equivalent Forced Outage Rates (“EFORs”) did HECO use in its  
3           production simulation for its rebuttal testimony?

4     A.   HECO used a revised set of EFORs based on actual 2004 experience provided in  
5           response to CA-IR-461.

6     Q.   Which set of EFORs did the CA use in its production simulation for its direct  
7           testimony?

8     A.   The CA used the EFORs “used in [HECO’s] November filing.” (See CA-T-3,  
9           page 34, lines 8 and 9.) The November filing refers to HECO’s direct testimony.  
10          For the production simulation used for direct testimony, HECO used average  
11          EFORs for the five-year period 1999 to 2003.

12    Q.   Why did the CA use the earlier set of EFORs?

13    A.   According to the CA, they used the earlier set of EFORs to be consistent with “the  
14          HECO planned outage schedule provided in the November filing.” (See CA-T-3,  
15          page 36, lines 3 and 4.) As I indicated earlier in my testimony, the HECO planned

16          outage schedule provided in the November filing was for HECO’s maintenance

1 the flexibility limitations resulting from the 2005 maintenance schedules.

2 Spinning Reserve Requirement

3 Q. What is spinning reserve?

4 A. Spinning reserve is the total amount of reserve capacity that is on-line but not  
5 currently serving any load, i.e., it is the difference between the total normal top  
6 load ratings of all operating units and the total output of all operating units.

7 Q. Why is spinning reserve important?

8 A. Spinning reserve is important because it can be immediately called upon to serve  
9 load in the event another operating unit trips out of service. This helps prevent  
10 interruptions of service to customers in the event a generating unit is unexpectedly  
11 lost from service.

12 Q. How much spinning reserve does HECO normally carry?

13 A. HECO generally carries enough spinning reserve to account for the loss of the  
14 largest operating unit less the amount of interruptible loads. Most of the time, the  
15 AES unit, with a rating of 180 MW, is the largest loaded unit. When the AES unit  
16 is not service, the next largest unit is Kahe 5, with a net rating of 135 MW.

17 Q. Why does HECO make an adjustment for interruptible loads?

18 A. HECO's capacity planning criteria are designed to provide for enough reserve  
19 capacity to be able to serve only firm loads. HECO does not plan to serve  
20 interruptible loads in the event of the loss of the largest operating unit. Therefore,  
21 from an operating perspective, as a minimum, HECO will need only enough  
22 spinning to cover for the loss of the largest operating unit less the amount of  
23 interruptible loads on the system at the time of the system peak.

24 For example, if the largest operating unit on the system is 180 MW and there  
25 are no interruptible loads, HECO's planning policy requires that a minimum of

1 180 MW of spinning reserve be carried on the system, the total of which will be  
2 allocated among the other operating units. Therefore, if the largest unit is  
3 unexpectedly forced out of service, the other units that are carrying the spinning  
4 reserve will ramp up in output to be able to make up for the output lost from the  
5 largest unit. If there are 10 MW of interruptible loads available, then HECO will  
6 carry a minimum of 170 MW of spinning reserve. If the largest unit is  
7 unexpectedly forced out of service, system frequency will decay and  
8 underfrequency relays will separate the 10 MW of interruptible loads from the  
9 grid. The remaining operating units will need to recover only 170 MW of output  
10 lost from the largest unit.

11 Q. What spinning reserve assumption was used in the production simulation in direct  
12 testimony?

13 A. As provided in the Spinning Reserve Requirement file (Rdlc1.spn), which was  
14 submitted to the CA in HECO's response to CA-IR-501, and as discussed with  
15 Mr. Issam Belmona of Sawvel and Associates on June 3, 2005, the spinning  
16 reserve assumption was 157 MW in all months of the test year. This was based on  
17 the largest unit rating at 180 MW and on having 23 MW of interruptible loads on  
18 the system in the test year, including 18 MW from the Residential Direct Load  
19 Control ("RDLC") and Commercial and Industrial Load Control ("CIDLC")  
20 Programs combined and 5 MW from Rider I customers.

21 Q. Was the spinning reserve assumption revised for the production simulation for

1 load management program impacts forecasted from 2005 through 2009 by 6 to 12  
2 MW.” HECO now estimates that it will have a cumulative amount of interruptible  
3 loads of about 13 MW by the end of the test year. HECO estimates that the  
4 amount of interruptible loads will be about 4 MW at the beginning of the year and  
5 the amount will ramp up gradually during the year. Therefore, for the production  
6 simulation, it was assumed that the spinning reserve amount needed would be the  
7 largest available unit (i.e., 180 MW when the AES unit is available or 135 MW  
8 when the AES unit is not available) less the increasing amount of interruptible  
9 loads. The month-by-month assumption for the amount of interruptible loads is  
10 shown in HECO-R-WP-511.

11 CHP Generation

12 Q. For HECO’s rebuttal testimony, what change was made to the CHP generation  
13 assumption?

14 A. In HECO’s direct testimony, it was assumed that CHP would provide 11.2 GWh  
15 of energy at the system level. (See HECO-403, line 7b.) As explained in HECO’s  
16 May 5<sup>th</sup> transmittal, in Attachment 1A, on page 1, and in HECO RT-7, no utility  
17 CHP is forecast to be installed during the 2005 test year because of the continued  
18 suspension of HECO’s CHP Program application in Docket No. 03-0366, the  
19 suspension of HECO’s and HELCO’s applications for individual CHP projects,  
20 and the subsequent cancellation of the Pacific Allied project. Therefore, CHP  
21 project revenues, expenses and capital costs are removed from the test year.  
22 There will be no energy produced by CHP in the test year under HECO’s  
23 proposed CHP Program.

24 Q. Did the CA treat the CHP generation the same way HECO treated CHP generation  
25 in HECO’s production simulation done for rebuttal testimony?

1 A. Yes, they did. (See CA-301, page 2, line 7.)

2 Distributed Generation ("DG") at HECO Sites

3 Q. Will the CHP capacity be replaced by some other form of energy production?

4 A. Yes, HECO continues to experience a reserve capacity shortfall and has a  
5 continuing need for new firm capacity. Since no new capacity will be acquired  
6 through the CHP Program in the test year, HECO is now pursuing installation of  
7 small distributed generating units at HECO sites. HECO's plans to install DGs at

8 HECO sites are discussed in HECO RT-7.

9 Q. How much DG capacity does HECO plan on installing in the test year?

10 A. As explained in HECO's May 5<sup>th</sup> transmittal, in Attachment 1A, on page 2,  
11 HECO is pursuing the installation of three 1.64 MW diesel generating units at  
12 three HECO sites.

13 Q. How will the installation of these DG units affect the areas of your testimony?

14 A. The installation of the DG units affects fuel oil expenses, fuel related expenses,  
15 and fuel inventory in the test year as shown in the table below. The DG operating  
16 assumptions were provided in HECO's May 5<sup>th</sup> transmittal, in Attachment 1A,  
17 page 5. The calculations for DG energy generation and DG fuel consumption are  
18 provided in HECO-R-409, page 6.

19

<u>Item</u>	<u>Amount</u>	<u>Reference</u>
DG Generation	7.4 GWh	HECO-R-403, page 1, line 7b
DG Fuel Oil Expense	\$984,000	HECO-R-401, page 2, line 3
DG Fuel Trucking Expense	\$55,000	HECO-R-405, page 2, line 8
DG Fuel Inventory	500 bbl	HECO-R-408, page 1, line 10
DG Fuel Inventory Value	\$41,943	HECO-R-408, page 1, line 15

1

2 Maintenance Schedule

3 Q. What maintenance schedule did HECO use in the production simulation for its  
4 rebuttal testimony?

5 A. HECO is using the maintenance schedule, dated January 12, 2004, in its  
6 production simulation for this rebuttal testimony. A copy of this maintenance  
7 schedule was provided to the CA in HECO's response to CA-IR-43, submitted on  
8 March 16, 2005. This maintenance schedule was also used in the production  
9 simulation for HECO's direct testimony.

10 In its May 5, 2005 submittal to the CA and DOD on 2005 test year rate case  
11 updates, HECO indicated that it would be using its revised maintenance schedule  
12 as of April 8, 2005 (provided in response to CA-IR-43 (revised April 21, 2005)) in  
13 its production simulation for rebuttal testimony. However, since that time, HECO  
14 has elected to use the January 12, 2004 maintenance schedule because it  
15 represents a normal overhaul year. As Mr. Aaron Fujinaka stated in HECO T-6,  
16 page 13, lines 13 and 14, "[t]he 2005 test year overhaul schedule [dated January  
17 12, 2004] shown at the bottom of HECO-627 represents a normal overhaul year."

18 Q. Which maintenance schedule did the CA use in its production simulation for its  
19 direct testimony?

20 A. The CA used HECO's maintenance schedule dated January 12, 2004. (See CA-T-  
21 3, page 34, lines 15 to 19. The CA refers to the January 12, 2004 maintenance  
22 schedule as the "schedules from the November filing.") This is the same  
23 maintenance schedule that HECO is using in its production simulation for rebuttal  
24 testimony.

25 Q. Why did the CA use the January 12, 2004 maintenance schedule?

1 A. The CA stated "I chose to use the planned outage schedules from the November  
2 filing because the Company indicated it is a normal planned outage schedule. I  
3 reviewed the updated outage schedules, but found them to be similar to the  
4 schedules in the November filing. Thus, I adopted the schedule from the  
5 November filing." (See CA-T-3, page 34, lines 15 to 19.)  
6

7 ISSUES RAISED BY THE CA

8 Q. What issues were raised by the CA within the areas covered by your direct or  
9 rebuttal testimony?

10 A. The CA raised issues concerning:

- 11 1) the calibration factor;  
12 2) the production simulation input files HECO submitted to the CA in response  
13 to their request; and  
14 3) the general practice with regard to updated information for production  
15 simulation results.

16 Calibration Factor

17 Q. What is a calibration factor?

18 A. A calibration factor is a constant number that can be greater than, equal to, or less  
19 than 1.00. The test year fuel consumption (in Btus) determined by the production  
20 simulation is multiplied by this factor.

21 Q. What calibration factors did HECO use in its direct testimony?

22 A. For direct testimony, the production simulation model results were calibrated to  
23 recorded fuel consumption in 2003. The calibration factors HECO used in its  
24 direct testimony were as follows:

25 Kahe 1.0061

1	Waiau	1.0211
2	Honolulu	0.9540
3	Diesel	1.1231

4 (See HECO's May 5<sup>th</sup> transmittal, Attachment 2, page 1.)

5 Q. What calibration factors is HECO using in its rebuttal testimony?

6 A. For rebuttal testimony, the production simulation model results were calibrated to  
7 recorded fuel consumption in 2004. The calibration factors HECO is using in its  
8 rebuttal testimony is as follows:

9	Kahe	1.0134
10	Waiau	1.0278
11	Honolulu	0.9747
12	Diesel	1.2288

13 (See HECO's May 5<sup>th</sup> transmittal, Attachment 2, page 1.)

14 Q. What issues has the CA raised with respect to the calibration factor?

15 A. The CA has the same concerns about the continued use of calibration factors as it  
16 expressed in the last HELCO rate case (Docket No. 99-0207). The CA's concerns  
17 are summarized in CA-T-3, page 38, line 7, to 39, line 18.

18 Q. In the Commission's Decision and Order ("D&O") in the last HELCO rate case  
19 (Docket No. 99-0207), did the Commission allow continued use of calibration  
20 factors?

21 A. Yes, they did. In D&O No. 18365, issued on February 8, 2001, on pages 15 to 18,  
22 the Commission considered HELCO's arguments for and the CA's arguments  
23 against continued use of a calibration factor. On pages 18 and 19, the  
24 Commission stated "The commission concludes that in lieu of elimination, it will  
25 allow for continued use of the calibration factor. HELCO must, however, on a

1           going forward basis, file with the commission and Consumer Advocate, annual  
2           reports identifying the actual system value for each year, the computer model  
3           results, and the adjustment resulting from the calibration factor. This should  
4           supply the commission and Consumer Advocate with appropriate data and  
5           information to more effectively address this issue in future rate cases.”

6           Q.    If not, how the CA process be used for the calibration factor?

- 7           A.    The CA recommends “using an average of the 2003 and 2004 calibration factors  
8                so as not to slant the calibration factors based on conditions in a particular year.”  
9                (See CA-T-3, page 40, lines 12 to 15.)
- 10          Q.    What is HECO’s position in response to the CA’s recommendation?
- 11          A.    HECO’s position is that the factors from the 2004 calibration year should be used.
- 12          Q.    What is the basis for HECO’s position that that the factors from the 2004  
13                calibration year should be used?
- 14          A.    First, the factors from the 2004 calibration year reflect the most recently available  
15                data. In the following HECO, HELCO and MECO rate cases, the Commission  
16                has accepted the results of production simulations that used calibration factors  
17                calculated from the latest available data:
- 18                1)    Docket No. 7700, HECO Test Year 1994

8           A.   HECO does not favor preparing and filing annual calibration factor reports simply  
9           because of the additional burden it places on already limited internal resources.  
10          Should the Commission deem it appropriate for HECO to file annual calibration  
11          factor reports and orders HECO to do so as part of this proceeding, HECO will  
12          file such reports.

15       A.     The CA did not have a specific recommendation as to when the reports should be

1

2     Production Simulation Files Submitted to the CA

3     Q     What contention has the CA made with respect to the production simulation input

1 hourly load to be served by firm and non-firm purchased power producers; c. the  
2 load carrying capability for each HECO and firm power producer-generating unit,  
3 with an indication as to which units are on AGC; d. the minimum run time for  
4 each individual generating units used by HECO, including the Kalaeloa and AES  
5 units; and e. HECO's unit commitment as used in production simulation." HECO  
6 provided the requested information on February 22, 2005. In CA-IR-501, which  
7 the CA submitted on March 29, 2005, they requested: "Please provide all input

8 data files for the P-MONTH Production Simulation Model, for the test year  
9 period, in electronic format and hard copy." HECO responded on April 19, 2005  
10 by providing the requested input files in electronic and hard copy format. HECO  
11 informed Mr. Issam Belmona of Sawvel and Associates, Inc., the CA's consultant  
12 in this area, of an error in identifying two input files on May 20, 2005, and on  
13 May 20, 2005, HECO submitted a revised response to CA-IR-501 to correct the  
14 error in which two file names were inadvertently transposed. While two files  
15 were mislabeled, the correct data were provided. These were the input files used  
16 to prepare the production simulation for HECO's direct testimony.

17 General Practice with Regard to Updated Information for Production Simulation Results

18 Q. What issue has the CA raised with respect to the general practice with regard to  
19 updated information for production simulation results?

20 A. The CA indicated they had a concern with their ability to independently assess the  
21 reasonableness of HECO's test year fuel and purchased power expenses. The CA  
22 stated, "in April and May 2005, HECO indicated that it was going to update its  
23 November 2004 direct testimony filing to reflect items such as increased fuel  
24 prices, changed generator outage schedules and removal of CHP and inclusion of  
25 Distributed Generation diesels. To-date, the production simulation results of such



1 updated test year numbers that would be provided in HECO's rebuttal testimony  
2 (including the results of an updated production simulation) should be submitted, to  
3 the extent possible, prior to the CA filing its direct testimonies. Such agreement  
4 was set forth in Stipulated Prehearing Order No. 13298. In MECO's Test Year  
5 1999 rate case, there was understanding between MECO and the CA that MECO  
6 would perform a production simulation run using inputs proposed by the CA, and  
7 this production simulation run would be completed prior to the CA filing its direct  
8 testimonies so that the results could be used in the CA's direct testimony. The CA  
9 was not planning on performing its own production simulation and that is why  
10 such an arrangement was made with MECO. (I do not know what is Kauai  
11 Electric's practice of providing updated production simulation results.)

12 There was no understanding between HECO and the CA that HECO would  
13 provide the results of an updated production simulation prior to the CA filing of  
14 its direct testimonies.

15 Second, While HECO did not provide the results of an updated production  
16 simulation prior to the CA filing of its direct testimonies, in order to simplify the  
17 proceeding and narrow and/or focus the issues, HECO provided through its May  
18 5<sup>th</sup> transmittal the known changes in production simulation inputs. However,  
19 HECO could not finalize the production simulation until it had the opportunity to  
20 review and take into account the positions of the other parties on the production  
21 simulation inputs. HECO provided the updates to the production simulation  
22 inputs (to the extent they were known at the time) at an earlier stage in the  
23 proceedings than updates have sometimes been provided in prior rate cases (e.g.,  
24 in rebuttal testimonies) in order to simplify the proceeding and narrow and/or  
25 focus the issues.

1  
2                   DOD ESTIMATES OF TEST YEAR FUEL EXPENSES.

---

3                   FUEL RELATED EXPENSES, AND FUEL INVENTORY

4       Q.   Did the DOD prepare estimates of test year fuel expenses, fuel related expenses  
5           and fuel inventory?

6       A.   Yes, they did.

7       Q.   Did the Department of Defense ("DOD") prepare a production simulation to  
8           determine fuel consumption and fuel expenses in order to compare to HECO's  
9           results?

10      A.   No, they did not.

11      Q.   How did the DOD prepare their estimates of test year fuel expenses, fuel related  
12           expenses and fuel inventory without preparing a production simulation?

13      A.   The DOD witness stated "I used HECO's originally filed rate base and net  
14           operating income as my starting point and have reflected my recommendations as  
15           adjustments to HECO's original filing." (See DOD T-1, page 5, lines 13 to 15.)  
16           In the case of fuel oil expenses and fuel inventory, the DOD used "placeholders"  
17           as adjustments that are added to the original values provided in HECO's direct  
18           testimony. These placeholders were proxy values extracted from the CA's  
19           exhibits and workpapers. (See DOD T-1, page 19, lines 2 to 4, for fuel inventory  
20           and DOD T-1, page 38, lines 1 to 3, for fuel oil expenses.)

21           Fuel Oil Expense and Fuel Related Expense

22      Q.   Did the DOD provide separate estimates for test year fuel oil expenses and test  
23           year fuel related expenses?

24      A.   Yes, they did. The DOD provided their estimate of test year fuel oil expenses and  
25           test year fuel related expenses as a sum but also provided a breakout of fuel

1 related expenses in Exhibit DOD-119.

2 Q. What was the DOD's estimate of the sum of test year fuel oil expenses and test  
3 year fuel related expenses?

4 A. The DOD began with HECO's estimate of test year fuel oil expenses plus fuel  
5 related expenses that were provided in direct testimony. This total value was  
6 \$292,704,000. (See HECO-401, page 1, line 3. See also Exhibit DOD-104, line  
7 5, column (A).) The DOD's placeholder or proxy value adjustment to HECO's  
8 direct testimony fuel expense is \$156,939,000. (See Exhibit DOD-126, line 6.)  
9 This value was extracted from the CA's Exhibit CA-101, Schedule C-4, line 3,  
10 column (E). Adding the two values (\$292,704,000 + \$156,939,000) results in  
11 \$449,643,000. The DOD then reduced this amount by \$627,000 as a proposed  
12 adjustment to the fuel related expense. (See DOD T-1, page 30, lines 7 to 15, and  
13 DOD-114, page 1, line 5.) They arrived at a final total of \$448,971,000 for the  
14 sum of fuel oil expenses and fuel related expenses. (See Exhibit DOD-104, line 5,  
15 column (C).)

16 Q. Does HECO agree with this amount?

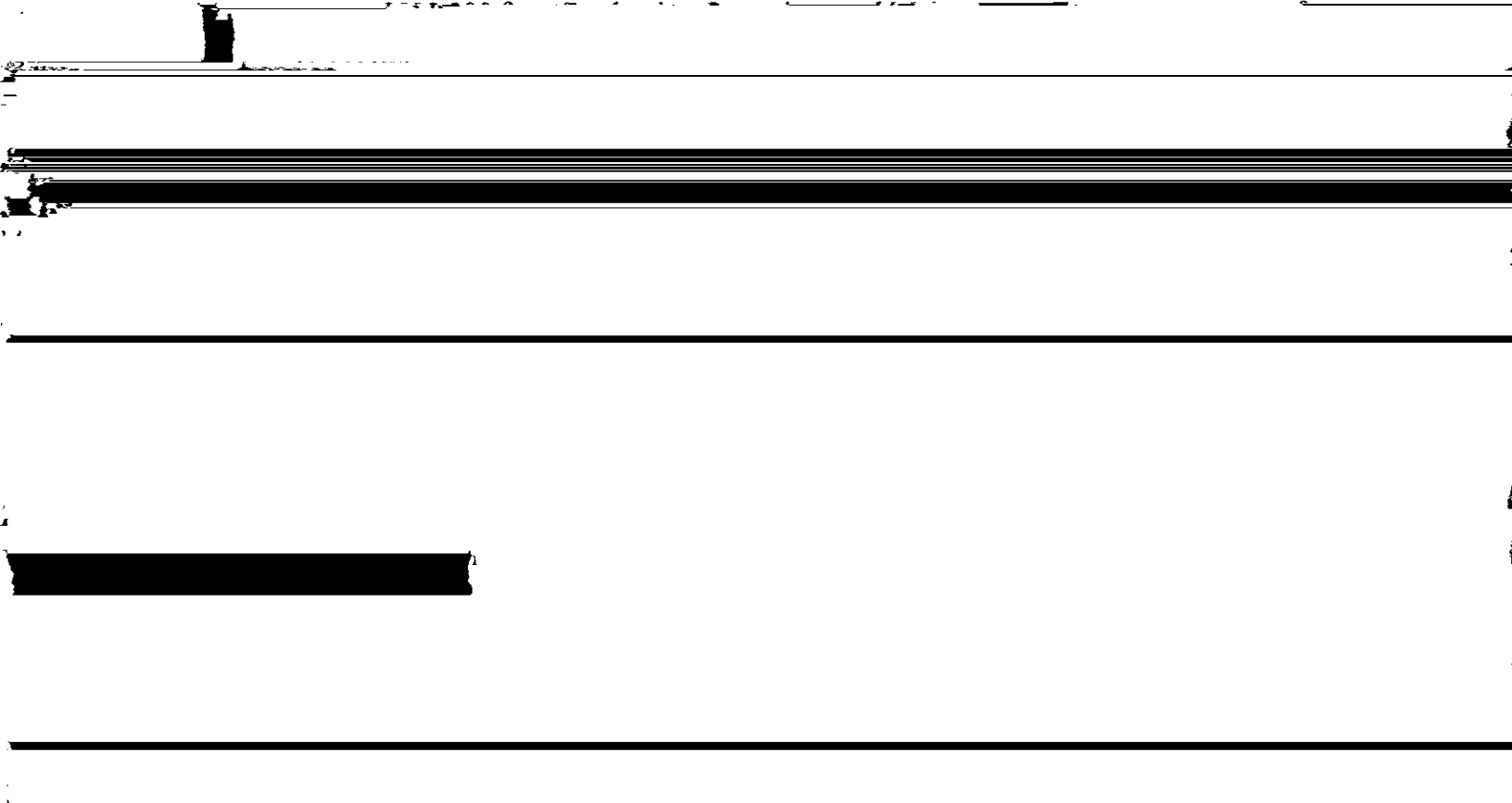
17 A. No, it does not. First, the DOD has made an error in its calculation. In the CA's  
18 calculation upon which the DOD based its calculation, the CA already reduced  
19 fuel related expenses by \$627,000. In CA-305, page 1, line 1, the CA reduced  
20 HECO's estimate of fuel related expenses of \$4,554,000 by \$627,000 to arrive at  
21 \$3,882,000. The CA then added their estimates for fuel trucking expenses and  
22 Petrospect expenses to arrive at total fuel related expenses of \$4,709,000. This is  
23 the value shown on Exhibit CA-101, Schedule C-4, page 1, line 2, column (D) and  
24 is used to arrive at the value of \$156,939,000. Therefore, this value already  
25 contains the \$627,000 reduction. By the DOD further reducing the \$156,939,000

1 amount (which the DOD used as a placeholder) by \$627,000, the DOD has  
2 double-counted the \$627,000 reduction. The DOD has acknowledged this error in  
3 response to HECO/DOD-IR-115.

4 Second, as previously discussed in my rebuttal testimony, HECO does not  
5 agree with some of the CA's estimates, including but not limited to, the CA's  
6 estimate of fuel trucking costs, DG fuel costs, and the calibration factor. Since the  
7 DOD relied upon the CA's calculations to determine its placeholder values,  
8 HECO does not agree with the DOD's estimates. HECO's estimate of the sum of  
9 fuel oil expense and fuel related expense is \$449,447,000. (See HECO-R-401,  
10 page 1, line 3.)

11 Q. Does HECO have other concerns with the DOD's estimate of test year fuel  
12 expenses?

13 A. Yes, it does. In Exhibit DOD-120, on line 2, the DOD shows a reduction of



1 and 3.) The second DOD estimate used an “alternative placeholder amount of  
2 \$15.77 million. The DOD’s second estimate is \$44,511,000 based on May 2005  
3 fuel prices, the LSFO inventory (789,909 barrels) given in HECO’s direct  
4 testimony (HECO 408, line 1, column (A)), and the diesel oil inventory (26,000

1 based on 788,080 barrels of LSFO with a value of \$42,415,000 and 26,009 barrels  
2 of diesel oil with a value of \$2,069,000 as shown on HECO-R-408, lines 1, 2 and  
3 3.

4  
5 SUMMARY

6 Q. Please summarize your testimony.

7 A. The testimony presented supports the reasonableness of the following values for  
8 the 2005 test year:

			<u>Units</u>
10	1) Fuel Expense	449,447,000	\$
11	a) Fuel Expense (Oil)	444,802,000	\$
12	b) Fuel-Related Expense	4,645,000	\$
13	2) Fuel Price		
14	a) Low Sulfur Fuel Oil	53.7346	\$/BBL
15	b) Diesel	79.4392	\$/BBL
16	3) Purchased Energy Forecast	3,426.3	GWH
17	4) Efficiency Factor (Sales Heat Rate)	0.011140	MMBTU/KWH
18			SALES
19	5) Fuel Inventory	44,484,000	\$

20 The above items were determined by detailed analyses and methodologies,  
21 are consistent with historical values considering known and expected conditions,  
22 and are consistent with all items in this case as they relate to each other.

23 Q. Does this conclude your testimony?

24 A. Yes, it does.

25

**Hawaiian Electric Company, Inc.**

**TEST YEAR FUEL EXPENSES**

<b>Line</b>	<b>Fuel Type</b>	<b>Reference</b>	<b>TY 2005 Fuel Expense (\$000)</b>
1.	<b>Total Fuel Oil Expense</b>	HECO-R-401, p. 2, Line 4	\$444,802
2.	<b>Total Fuel Related Expense</b>	HECO-R-405, p. 1, Line 4	\$4,645
3.	<b>TOTAL FUEL EXPENSE</b>		<b>\$449,447</b>

**Hawaiian Electric Company, Inc.**

**TEST YEAR FUEL EXPENSES  
TOTAL FUEL OIL EXPENSES**

<b>Line</b>	<b>Fuel Type</b>	<b>Reference</b>	<b>TY 2005 Fuel Oil Expense (\$000)</b>
1.	Low Sulfur Fuel Oil	HECO-R-404, p. 1, Line 4	\$441,621
2.	Diesel Fuel Oil	HECO-R-404, p. 1, Line 6	\$2,197
3.	Sub. DG Diesel Fuel Oil	HECO-R-404, p. 1, Line 8	\$984
4.	TOTAL FUEL OIL EXPENSE		\$444,802

Note: Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

**FUEL PRICES FOR 2005 TEST YEAR  
WEIGHTED AVERAGE FUEL PRICES**

Line	LSFO	(A) Chevron	(B) Tesoro	(C) = (A) + (B) (C) Total	
1.	Test Year Percent of Purchases <sup>1</sup>	61.34%	38.66%	100.00%	
2.	Price per Barrel (\$/Barrel) <sup>2</sup>	\$ 53.4192	\$ 54.2351		
3.	Weighted Average \$/Barrel (Line 1 * Line 2)	\$ 32.7673	\$ 20.9673	\$ 53.7346	
4.	Diesel <sup>2</sup>	\$ 79.4392		\$ 79.4392	
		(D) LSFO Honolulu	(E) LSFO Kahe	(F) LSFO Waiau	(G) Waiau Diesel
5.	Fuel Price	\$ 53.7346	\$ 53.7346	\$ 53.7346	\$ 79.4392
6.	Thruput <sup>3</sup>	\$ 2.4665	\$ -	\$ -	\$ -
7.	Total \$/Barrel	\$ 56.2012	\$ 53.7346	\$ 53.7346	\$ 79.4392
8.	Petrospect Cost <sup>4</sup>	\$ 0.0124	\$ 0.0124	\$ 0.0124	\$ 0.0360
9.	Grand Total \$/Barrel	\$ 56.2136	\$ 53.7470	\$ 53.7470	\$ 79.4752

<sup>1</sup> Chevron and Tesoro split based upon 2004 actual nomination of LSFO.

<sup>2</sup> Priced based on May 2005 Contract Fuel Prices, which was submitted in the May 5, 2005 Transmittal on Attachment 1B.

<sup>3</sup> Honolulu's LSFO - \$2.925/barrel for 1st 105,000 barrels, \$2.230/barrel for next 95,000 barrels, \$1.900/barrel \$1.900/barrel for barrels exceeding 200,000 bbls. Substation DG Diesel Oil at \$4.41/barrel (10.5¢/gallon).

<sup>4</sup> Petrospect Cost - 2005 Operating Budget Amounts pro-rated on a \$/barrel based on the barrels shown on HECO-404.

**Hawaiian Electric Company, Inc.**  
**2005 TEST YEAR GENERATION**

<b>Line</b>	<b>(A) Energy (GWh)</b>	<b>(B) Percent of Net System Input</b>
<b>1. Sales</b>	7,856.0	
<b>2. Company Use<sup>1</sup></b>	15.4	
<b>3. Sales + NC</b>	7,871.4	
<b>4. Losses<sup>2</sup></b>	383.9	
<b>5. Net System Input</b>	8,255.3	100.00%
<b>6. - Purchase Power<sup>3</sup></b>	3,426.3	41.50%
<b>7. Net HECO</b>	4,829.0	58.50%
<b>7a. Central Station</b>	4,821.6	58.41%
<b>7b. Substation DG</b>	7.4	0.09%

<sup>1</sup> No Charge based on 2000-2004 5 year average, 15.392 MWh. (HECO-RWP-403, p. 1)

<sup>2</sup> Losses of 4.65% based on 5-year average (2000-2004)

<sup>3</sup> HECO-R-502.

Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE  
(Contract Fuel Prices)

Line	LSFO	(A) Fuel Consumption (Barrels)	(B) <sup>1</sup> Contract Prices (\$/bbl)	(C) = (A) x (B) (C) Fuel Expense (\$000)	
1.	Honolulu	245,301	53.7346	\$ 13,181	
2.	Kahe	5,776,468	53.7346	\$ 310,396	
3.	Waiau-Steam	2,196,784	53.7346	\$ 118,043	
4.	Subtotal	8,218,553		\$ 441,621	
5.	Waiau-Diesel	27,658	79.4392	\$ 2,197	
6.	Subtotal	27,658		\$ 2,197	
7.	Central Station Total	8,246,211		\$ 443,818	
8.	Substation DG	12,384	79.4392	\$ 984	
9.	Grand Total	8,258,594		\$ 444,802	
		Composite Fuel Price		53.8593	\$/bbl

<sup>1</sup> HECO-R-402, Line 5.

**Hawaiian Electric Company, Inc.**

**DERIVATION OF FUEL EXPENSE**  
**(Including Trucking and Petrospect Costs)**

Line	LSFO	(A) Fuel Consumption (Barrels)	(B) <sup>1</sup> Fuel Costs (\$/bbl)	(C) = (A) x (B)	
				(C) Fuel Expense (\$000)	
1.	Honolulu	245,301	56.2136	\$	13,789
2.	Kahe	5,776,468	53.7470	\$	310,468
3.	Waiau-Steam	2,196,784	53.7470	\$	118,071
4.	Subtotal	8,218,553		\$	442,328
5.	Waiau-Diesel	27,658	79.4752	\$	2,198
6.	Subtotal	27,658		\$	2,198
7.	Central Station Total	8,246,211		\$	444,526
8.	Substation DG	12,384	83.8852	\$	1,039
9.	Grand Total	8,258,594		\$	445,565
		<b>Composite Fuel Price</b>		<b>53.9517</b>	<b>\$/bbl</b>

<sup>1</sup> HECO-R-402, Line 9.

**Hawaiian Electric Company, Inc.**  
**TEST YEAR FUEL RELATED EXPENSES**

<b>Line</b>		<b>Dollars (\$000)</b>	<b>Reference</b>
<u>1.</u>	<b>Fuel Handling Expenses</b>	<u>\$ 3,882</u>	<u>HECO-RWP-410</u>
2.	<b>Fuel Trucking Expenses</b>	\$ 660	HECO-R-405, page 2
3.	<b>Petrospect Expenses</b>	\$ 103	HECO-R-405, page 3
4.	<b>Total</b>	<u><u>\$ 4,645</u></u>	

Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE  
(Trucking Costs)

Line	LSFO	(A) Fuel Consumption (Barrels)	(B) <sup>1</sup> Trucking Cost (\$/bbl)	(C) = (A) x (B)
				(C) Fuel Expense (\$000)
1.	Honolulu	245,301	2.4665	\$ 605
2.	Kahe	5,776,468	-	\$ -
3.	Waiau-Steam	2,196,784	-	\$ -
4.	Subtotal	8,218,553		\$ 605
5.	Waiau-Diesel	27,658	-	\$ -
6.	Subtotal	27,658		\$ -
7.	Central Station Total	8,246,211		\$ 605
8.	Substation DG	12,384	4.4100	\$ 55
9.	Grand Total	8,258,594		\$ 660

<sup>1</sup> HECO-R-402, Line 6.

Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE  
(Petrospect Costs)

Line	LSFO	(A) Fuel Consumption (Barrels)	(B) <sup>1</sup> Petrospect Cost (\$/bbl)	(C) = (A) x (B) (C) Fuel Expense (\$000)
1.	Honolulu	245,301	0.0124	\$ 3
2.	Kahe	5,776,468	0.0124	\$ 72
3.	Waiau-Steam	2,196,784	0.0124	\$ 27
4.	Subtotal	8,218,553		\$ 102
5.	Waiau-Diesel	27,658	0.0360	\$ 1
6.	Subtotal	27,658		\$ 1
7.	Central Station Total	8,246,211		\$ 103
8.	Substation DG	12,384	0.0360	\$ 0
9.	Grand Total	8,258,594		\$ 103

<sup>1</sup> HECO-R-402, Line 8.

Hawaiian Electric Company, Inc.

TEST YEAR FUEL EFFICIENCY

Line

ENERGY

1.	Company Generated Energy	4,828.9 Net GWh
2.	Central Station Generated Energy	4,821.5 Net GWh
3.	Steam Generated Energy	4,815.0 Net GWh
4.	CT Generated Energy	6.5 Net GWh
5.	Sub. DG Generated Energy	7.4 Net GWh
6.	Test Year Sales	7,856.0 Net GWh

FUEL CONSUMPTION

7.	Total Fuel Consumed	51,189,669 MBtu
8.	Central Station Fuel Consumed	51,117,102 MBtu
9.	Steam Fuel Consumed	50,955,027 MBtu
10.	CT Fuel Consumed	162,075 MBtu
11.	Sub. DG Fuel Consumed	72,568 MBtu

HEAT RATE

12.	Total Heat Rate	10,601 Btu/kWh
13.	Central Station Heat Rate	10,602 Btu/kWh
14.	Steam Heat Rate	10,583 Btu/kWh
15.	CT Heat Rate	25,070 Btu/kWh
16.	Sub. DG Heat Rate	9,833 Btu/kWh

17.	HECO Central Station Generation of Net System Input	58.41% Percent
18.	Sales Heat Rate - Central Station	0.011140 MBtu/kWh Sales <sup>1</sup>

Reference

<sup>1</sup> 51,117,102 MBtu / (7,856.0 GWh x 58.41% x 1,000,000 kWh/GWh) = 0.011140 MBtu/kWh Sales.

Source: HECO-R-409, page 2 and HECO-R-407.

Hawaiian Electric Company, Inc.

**HISTORICAL FUEL EFFICIENCY**  
(Btu/Net kWh)

<u>Line</u>	(A) <u>2000</u>	(B) <u>2001</u>	(C) <u>2002</u>	(D) <u>2003</u>	(E) <u>2004</u>	(F) Test Year <u>2005</u>
1. Central Station Steam	10,463	10,387	10,414	10,413	10,540	10,583 <sup>1</sup>
2. Percent Increase		-0.7%	0.3%	0.0%	1.2%	0.4%
3. Central Station Diesel	32,918	29,053	21,106	21,081	21,327	25,070 <sup>2</sup>
4. Percent Increase		-11.7%	-27.4%	-0.1%	1.2%	17.6%
5. Central Station Average	10,482	10,406	10,436	10,452	10,621	10,602 <sup>3</sup>
6. Percent Increase		-0.7%	0.3%	0.2%	1.6%	-0.2%
7. Substation DG						9,833 <sup>4</sup>
8. Percent Increase						N/A

<sup>1</sup> HECO-R-406, Line 14.

<sup>2</sup> HECO-R-406, Line 15.

<sup>3</sup> HECO-R-406, Line 13.

<sup>4</sup> HECO-R-406, Line 16.

Hawaiian Electric Company, Inc.

TEST YEAR FUEL OIL INVENTORY

Line	LSFO	(A) Average Barrels	(B) Price per Barrel	(C) = (A) x (B) (C) Fuel Oil Inventory (\$000)
1.	Residual Fuel Oil	788,080	53.8207	\$ 42,415
2.	Diesel Oil	26,009	79.5599	\$ 2,069
3.	TOTAL INVENTORY	814,089		\$ 44,484
4.	AVERAGE RESIDUAL FUEL OIL PRICE			
5.	Residual Fuel Oil Expense (HECO-R-404, p. 2, Line 4, Column C)			\$ 442,328
6.	Barrels of Residual Fuel Oil (HECO-R-404, p. 2, Line 4, Column A)			8,218,553
7.	Average Price per Barrel (Line 5 ÷ Line 6)			\$ 53.8207
8.	AVERAGE DIESEL OIL PRICE			
9.	Central Station Diesel Oil Inventory Volume (HECO-R-411, Line 6)			25,509
10.	Substation DG Diesel Oil Inventory Volume (HECO-R-411, Line 7)			500
11.	Total Diesel Oil Inventory Volume (Line 9 + Line 10)			26,009
12.	Central Station Diesel Oil Price (HECO-R-404, Page 2, Line 5, Column B)			\$ 79.4752
13.	Substation DG Diesel Oil Price (HECO-R-404, Page 2, Line 8, Column B)			\$ 83.8852
14.	Central Station Diesel Oil Inventory Value (Line 9 * Line 12)			\$ 2,027,332
15.	Substation DG Diesel Oil Inventory Value (Line 10 * Line 13)			\$ 41,943
16.	Total Diesel Oil Inventory Value (Line 14 + Line 15)			\$ 2,069,275
17.	Average Diesel Oil Price (Line 16 ÷ Line 11)			\$ 79.5599

Hawaiian Electric Company, Inc.

DERIVATION OF RESIDUAL FUEL OIL INVENTORY

Line	Energy (GWh)
1. Forecast Residual Fuel Oil Consumption <sup>1</sup>	8,218,553 Barrels
2. Burn Rate (Line 1 / 365 days)	22,517 Barrels/Day
3. 35 Day Inventory (Line 2 X 35 days)	788,080 Barrels
4. Fuel Price <sup>2</sup>	\$ 53.8207 \$/Barrel
5. Residual Fuel Oil Inventory (Line 3 x Line 4)	\$ 42,415 \$000

<sup>1</sup> See HECO-R-404, line 4, column A.

<sup>2</sup> See HECO-R-408, line 7.

**Hawaiian Electric Company, Inc.**  
**2005 Production Simulation - (Rate Case Rebuttal Testimony - Negotiations Run #1)**  
Sales and Peak Forecast dated May 5, 2005 Transmittal to CA  
Maintenance Schedule dated January 12, 2004  
Fuel Prices from May 2005 Contract Price Sheet

Month	Mbtu Consumption			Kahe	Net MWh Generation			Total	Net Heat Rate
	Kahe	Waiau	Honolulu		Waiau	Honolulu	Diesel		
Jan	2,526,188	1,206,390	163,431	244,744	102,731	12,891	696	361,062	10,840
Feb	2,311,419	1,022,566	90,285	227,858	87,788	6,941	1	322,588	10,615
Mar	3,077,767	1,254,405	135,940	303,095	108,080	10,635	562	422,372	10,612
Apr	3,087,568	1,186,476	191,531	305,024	100,245	15,625	3,010	423,904	10,711
May	2,858,839	1,088,323	112,934	280,973	95,047	8,904	9	384,933	10,548
Jun	2,887,352	1,167,435	111,012	284,816	101,012	8,665	4	394,497	10,560
Jul	3,045,780	1,222,748	99,657	299,126	105,605	7,882	1,029	413,642	10,623
Aug	3,120,002	1,284,763	167,842	308,928	110,036	13,213	336	432,513	10,592
Sep	3,363,710	1,262,033	158,264	331,602	108,864	12,421	504	453,391	10,580
Oct	3,379,015	1,082,313	99,941	332,481	94,667	7,845	29	434,822	10,492
Nov	2,978,287	1,080,077	107,036	291,786	94,112	8,199	126	394,223	10,574
Dec	3,178,177	762,529	82,990	311,663	65,354	6,354	159	383,530	10,502
<b>Total</b>	<b>35,814,103</b>	<b>13,620,059</b>	<b>1,520,865</b>	<b>3,522,096</b>	<b>1,173,541</b>	<b>119,375</b>	<b>6,465</b>	<b>4,821,477</b>	<b>10,602</b>
	10,186	11,606	12,740	73.1%	24.3%	2.5%	0.1%	100.0%	
<b>Sub. DG</b>								<b>7,380</b>	<b>9,833</b>
<b>HECO w/CHP</b>								<b>4,828,857</b>	<b>10,601</b>

**AES Hawaii, Inc**  
**Production Simulation - (Rate Case Rebuttal Testimony - Negotiations Ru**  
Sales and Peak Forecast dated May 5, 2005 Transmittal to CA  
Maintenance Schedule dated January 12, 2004  
Fuel Prices from May 2005 Contract Price Sheet

Month	<u>2 Boiler Operation</u>			<u>1 Boiler Operation</u>		
	MWh	Hrs	Avg MW	MWh	Hrs	Avg MW
Jan	132,581	737	180.00	0	0	0.00
Feb	119,750	665	180.00	0	0	0.00
Mar	132,581	737	180.00	0	0	0.00
Apr	128,304	713	180.00	0	0	0.00
May	132,581	737	180.00	0	0	0.00
Jun	128,304	713	180.00	0	0	0.00
Jul	132,581	737	180.00	0	0	0.00
Aug	132,581	737	180.00	0	0	0.00
Sep	68,429	380	180.00	29,938	333	90.00
Oct	132,581	737	180.00	0	0	0.00
Nov	128,304	713	180.00	0	0	0.00
Dec	132,581	737	180.00	0	0	0.00
<b>Total</b>	<b>1,501,158</b>	<b>8,340</b>	<b>180.00</b>	<b>29,938</b>	<b>333</b>	<b>90.00</b>

**Kalaeloa Partners**  
**Production Simulation - (Rate Case Rebuttal Testimony - Negotiations Ru**  
Sales and Peak Forecast dated May 5, 2005 Transmittal to CA  
Maintenance Schedule dated January 12, 2004  
Fuel Prices from May 2005 Contract Price Sheet

Month	<u>2 CT Operation</u>			<u>1 CT Operation</u>		
	MWh	Hrs	Avg MW	MWh	Hrs	Avg MW
Jan	128,247	618	207.60	10,692	119	90.00
Feb	116,046	570	203.50	8,554	95	90.00
Mar	80,585	392	205.55	20,315	226	90.00
Apr	24,034	115	209.29	49,540	550	90.00
May	130,885	638	205.29	8,910	99	90.00
Jun	129,064	618	208.92	8,554	95	90.00
Jul	128,972	618	208.77	10,692	119	90.00
Aug	134,077	642	209.00	8,554	95	90.00
Sep	128,284	614	209.00	8,910	99	90.00
Oct	124,787	598	208.69	12,474	139	90.00
Nov	128,348	618	207.76	8,554	95	90.00
Dec	129,197	626	206.49	9,979	111	90.00
<b>Total</b>	<b>1,382,528</b>	<b>6,665</b>	<b>207.44</b>	<b>165,726</b>	<b>1,841</b>	<b>90.00</b>

**H-POWER**  
**2005 Production Simulation - (Rate Case Rebuttal Testimony - Negotiations Run #1)**  
Sales and Peak Forecast dated May 5, 2005 Transmittal to CA  
Maintenance Schedule dated January 12, 2004  
Fuel Prices from May 2005 Contract Price Sheet

Month	<u>On-Peak</u>	<u>Off-Peak</u>	<u>Total</u>	NonFirm
Jan	17,968	12,834	30,802	594
Feb	16,229	11,592	27,821	536
Mar	9,596	6,854	16,450	594
Apr	16,358	11,684	28,042	575
May	17,968	12,834	30,802	594
Jun	17,388	12,420	29,808	575
Jul	17,968	12,834	30,802	594
Aug	17,968	12,834	30,802	594
Sep	17,388	12,420	29,808	575
Oct	17,195	12,282	29,477	594
Nov	16,100	11,500	27,600	575
Dec	16,164	11,546	27,710	594
<b>Total</b>	<b>198,288</b>	<b>141,634</b>	<b>339,922</b>	<b>6,990</b>

H-POWER EAF of 90%  
NonFirm IPP - Tesoro 6,254,736 kWh and Chevron 735,181 kWh

**Substation DG Generation**  
**2005 Production Simulation - (Rate Case Rebuttal Testimony - Negotiations Run #1)**  
Sales and Peak Forecast dated May 5, 2005 Transmittal to CA  
Maintenance Schedule dated January 12, 2004  
Fuel Prices from May 2005 Contract Price Sheet

Month	System Level	
	<u>MWh</u>	<u>MBtu</u>
Jan	0	0
Feb	0	0
Mar	0	0
Apr	0	0
May	0	0
Jun	0	0
Jul	1,476	14,514
Aug	1,476	14,514
Sep	2,952	29,027
Oct	1,476	14,514
Nov	0	0
Dec	0	0
<b>Total</b>	<b>7,380</b>	<b>72,568</b>

Net Heat Rate (Btu/kWh)

9,833

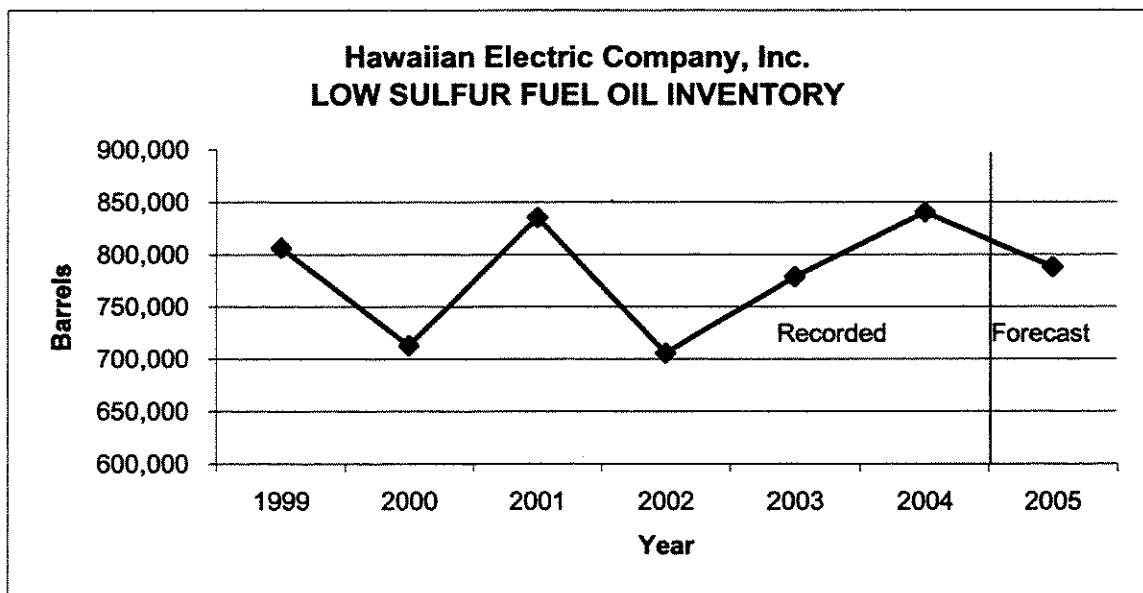
CHP MWh: 14.76 MW \* 100 hours = 1,476 MWh

CHP MBtu: 1,476 MWh \* 9,833 Btu/kWh \* 1000 kWh/MWh ÷ 1000000 Btu/MBtu = 14,514 MBtu

**Hawaiian Electric Company, Inc.**

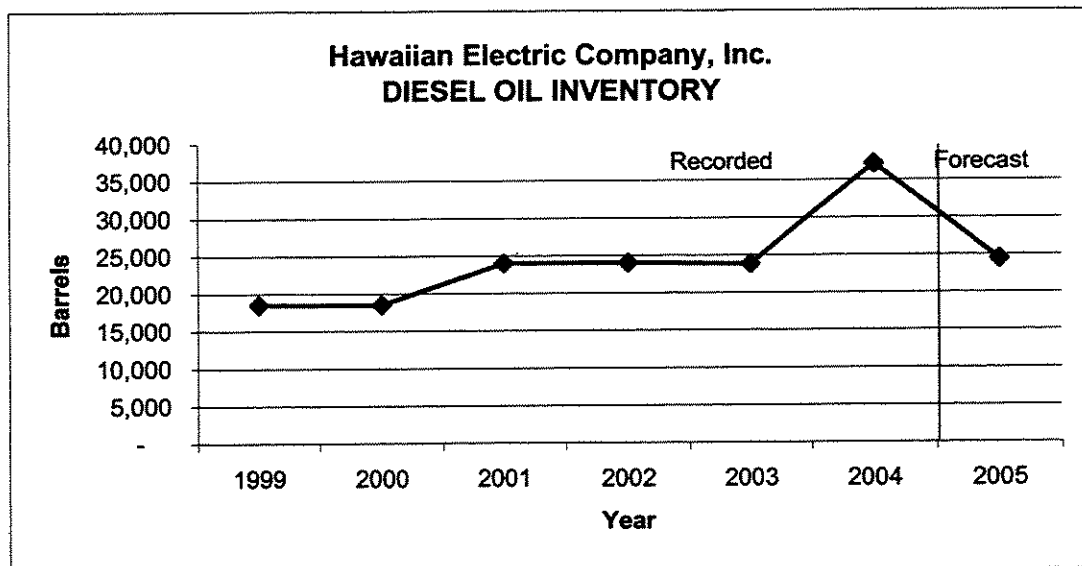
**LOW SULFUR INVENTORY 2000-2004**

Line	Year	(A)	(B)	(C) = (B) / (A)
		Barrels Consumed Per Day	Average Ending Inventory (Barrel)	Average Days Supply
1.	2000	20,355	712,870	35
2.	2001	20,328	835,100	41
3.	2002	20,888	705,692	34
4.	2003	20,974	778,717	37
5.	2004	22,229	840,342	38
6.	1999 - 2003 Average	20,955	774,544	37



**Hawaiian Electric Company, Inc.**  
**DIESEL OIL INVENTORY 2000-2004**

Line	Year	(A)	(B)	(C) = (B) / (A) (C)
		Barrels Consumed Per Day	Average Ending Inventory (Barrel)	Average Days Supply
1.	2000	60	18,522	308
2.	2001	61	23,992	393
3.	2002	79	24,010	306
4.	2003	170	23,827	140
5.	2004	371	37,194	100
6.	2000 - 2004 Average Central Station Inventory	148	25,509	
7.	DG Inventory		<u>500</u>	
6.	Total Diesel Oil Inventory		<u><u>26,009</u></u>	



Hawaiian Electric Company, Inc.

DERIVATION OF DIESEL FUEL OIL INVENTORY  
DERIVED ON DAILY CONSUMPTION BASIS

**Line**

---

1. Forecast Diesel Fuel Oil Consumption	27,658 Barrels
2. Burn Rate (Line 1 / 365 days)	76 Barrels/Day
3. 35 Day Inventory (Line 2 X 35 days)	2,652 Barrels
4. Continuous 24 Hour Consumption <sup>1</sup>	5,374 Barrels/Day
5. Residual Fuel Oil Inventory (Line 3 x Line 4)	0.5 Days

<sup>1</sup> Assumption: W9 and W10 are run at 53 MW and 50 MW respectively for 24 hours.  
W9:  $\{[192.5650 + (7.6075 * 53) + (.02832 * 53^2)] * 24\} / 5.86 = 2,765.79$  Barrels/Day  
W10:  $\{[194.6036 + (7.3976 * 50) + (.02899 * 50^2)] * 24\} / 5.86 = 2,608.70$  Barrels/Day  
W9 + W10 combined = 5,374.49 Barrels/Day

**Hawaiian Electric Company, Inc.**

**DAYS OF FULL LOAD CONSUMPTION**

**Line**

---

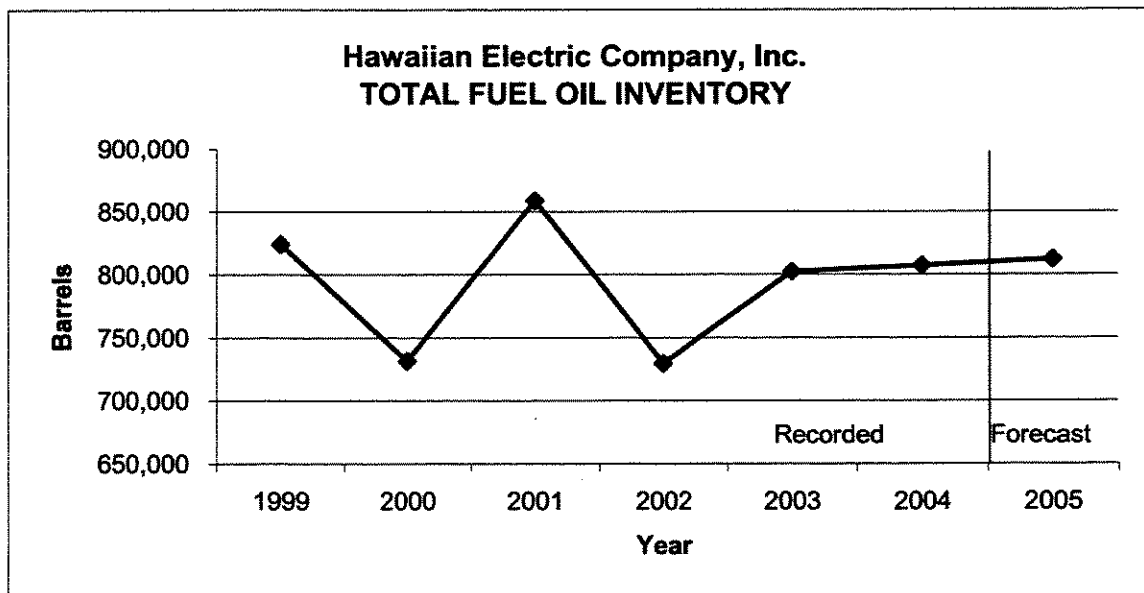
<b>1. HECO's Test Year Diesel Inventory</b>	<b>26,009 Barrels</b>
<b>2. HECO's Full Load Consumption</b>	<b>5,374 Barrels/Day</b>
<b>3. Days at Full Load Consumption</b>	<b>4.8 Days</b>

<sup>1</sup> Assumption: W9 and W10 are run at 53 MW and 50 MW respectively for 24 hours.  
W9:  $\{[192.5650 + (7.6075 * 53) + (.02832 * 53^2)] * 24\} / 5.86 = 2,765.79$  Barrels/Day  
W10:  $\{[194.6036 + (7.3976 * 50) + (.02899 * 50^2)] * 24\} / 5.86 = 2,608.70$  Barrels/Day  
W9 + W10 combined = 5,374.49 Barrels/Day

**Hawaiian Electric Company, Inc.**

**HISTORICAL FUEL INVENTORY COMPARED WITH TEST YEAR  
AVERAGE MONTHLY INVENTORY**

Line	Year	(A)	(B)	(C) = (A) + (B) (C)
		L S F O Barrels	Diesel Barrels	Total Barrels
1.	2000	712,870	18,522	731,392
2.	2001	835,100	23,992	859,092
3.	2002	705,692	24,010	729,702
4.	2003	778,717	23,827	802,544
5.	2004	840,342	37,194	877,536
6.	2000 - 2004 Average	774,544	25,509	800,053



REBUTTAL TESTIMONY OF  
DANIEL S. W. CHING

DIRECTOR  
POWER PURCHASE DIVISION  
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: PURCHASED POWER EXPENSE

INTRODUCTION

Q. Please state your name and business address.

A. My name is Daniel S. W. Ching. My business address is 475 Kamehameha Highway, Pearl City, Hawaii.

Q. Have you provided testimony previously as a witness in this proceeding?

A. Yes. I sponsored written direct testimony in HECO T-5 related to Purchased Power Expense.

Q. What is the scope of your rebuttal testimony?

A. My rebuttal testimony will present HECO's rebuttal position with respect to purchased power expense, and comment on the Consumer Advocate's ("CA") and Department of Defense's ("DOD") positions.

HECO'S REBUTTAL POSITION

Q. What is HECO's position with respect to purchased power expense?

A. HECO's revised 2005 test year estimate of purchased power expense is \$345,434,080, as shown on HECO-R-501. The revised estimate of purchased energy is 3,426 GWh, as shown on HECO-R-502. The purchased power expense is comprised of purchased energy expense of \$236,958,383, and purchased capacity expense of \$108,475,697, as shown on HECO-R-501.

Purchased Energy

Q. Why has HECO revised its estimate of purchased energy for the 2005 test year?

A. As discussed by Mr. Sakuda in HECO RT-4, HECO has updated its direct testimony test year production simulation to take into account changes in assumptions to no-charge energy, transmission losses, spinning reserve, and fuel prices.

1 Q. How has HECO revised its test year estimate of energy purchases?

2 A. HECO has increased its estimate of energy purchased by 45 GWh, from 3,381  
3 GWh to 3,426 GWh. See HECO-R-503.

4 Purchased Energy Expense

5 Q. What is the revised test year purchased energy expense?

6 A. The purchased energy expense is \$236,958,000. See HECO-R-504.

7 Q. How has HECO revised its test year estimate of purchased energy expense?

8 A. The test year purchased energy expense has increased by \$47,015,000 from  
9 \$189,943,000 to \$236,958,000. See HECO-R-505.

10 Q. Why did HECO revise the test year estimate of purchased energy expense?

11 A. The primary reasons for the revision are to reflect 1) the increase in the fuel price  
12 assumption used to calculate the fuel component of the energy charge for  
13 Kalaeloa, 2) the increase in the avoided cost assumption used to calculate the  
14 energy charge for H-POWER and for the as-available producers Chevron and  
15 Tesoro, 3) the increase in GNPIPD used to calculate the non-fuel component of  
16 the energy charge for Kalaeloa and the O&M component of the energy charge for  
17 AES Hawaii, 4) the increase in energy dispatch from Kalaeloa.

18 Q. Please elaborate on the change in the fuel price assumption used to calculate the  
19 fuel component of the energy charge for Kalaeloa.

20 A. The assumed fuel price for Kalaeloa in the direct testimony was \$36.28. See  
21 HECO-WP-501. The assumed fuel price for rebuttal testimony is \$51.802. See  
22 HECO-RWP-501. It represents the preliminary estimate of the May 2005 fuel  
23 price used in the calculation of the fuel component of the energy charge for  
24 Kalaeloa's May 2005 energy deliveries.

25 Q. Please elaborate on the change in the avoided cost assumption used to calculate

1 the energy charge for Chevron and Tesoro.

2 A. The assumed avoided energy cost payment rates in the direct testimony were 7.90  
3 cents/kWh (on-peak) and 6.08 cents/kWh (off-peak). As discussed by Mr. Hee in  
4 HECO RT-10, the revised 2005 test year avoided energy cost payment rates are  
5 12.02 cents/kWh (on-peak), and 9.13 cents/kWh (off-peak). See HECO-RWP-  
6 1012, p. 7.

7 Q. Are the on-peak and off-peak avoided energy cost payment rates of 12.02  
8 cents/kWh and 9.13 cents/kWh used to calculate the revised energy charge for H-  
9 POWER?

10 A. No. The payment rates used to calculate the energy charge for H-POWER in the  
11 direct testimony were 7.90 cents/kWh (on-peak) and 6.08 cents/kWh (off-peak).  
12 As stated in HECO T-5 at page 8, line 25 and page 9, lines 1 and 2, if the avoided  
13 energy cost payment rates reach certain thresholds, the payment rates for H-  
14 POWER are adjusted from the filed avoided energy cost rates in accordance with  
15 the power purchase contract with H-POWER ("H-POWER contract").

16 Since the revised 2005 test year avoided energy cost payment rates are  
17 above the threshold amounts in the H-POWER contract, they must be adjusted.  
18 At the 12.02 cents/kWh (on-peak) and 9.13 cents/kWh (off-peak) levels, the  
19 adjustment factor is 25% of the differential between the avoided energy cost  
20 payment rates and the floor level rates in accordance with the H-POWER contract.  
21 As a result, the assumed on-peak and off-peak payment rates for H-POWER for  
22 the rebuttal testimony are 10.817 cents/kWh and 8.247 cents/kWh, respectively.  
23 See HECO-RWP-503.

24 Q. Please elaborate on the changes in GNPIPD.

25 A. The GNPIPD values used in the rebuttal testimony reflect the applicable period

1 final values published by the Bureau of Economic Analysis. See HECO-RWP-  
2 501 for the GNPIPD values used in calculating the Kalaeloa energy expense, and  
3 HECO-RWP-502 for the GNPIPD values used in calculating the AES Hawaii  
4 energy expense.

5 Q. What is the difference in the energy dispatch amount of Kalaeloa between the  
6 rebuttal testimony and the direct testimony?

7 A. The production simulation used for the rebuttal testimony increased Kalaeloa's  
8 energy dispatch amount by 45 GWh, from 1,503 GWh in direct testimony to 1,548  
9 GWh. See HECO-R-503.

10 Purchased Capacity Expense

11 Q. What is the revised test year purchased capacity expense?

12 A. The purchased capacity expense is \$108,476,000. See HECO-R-506.

13 Q. How has HECO revised its test year estimate of purchased capacity expense?

14 A. The 2005 test year purchased capacity expense decreased by \$146,000 from  
15 \$108,621,000 in direct testimony to \$108,476,000. See HECO-R-507.

16 Q. Why did HECO revise its test year estimate of purchased capacity expense?

17 A. The revision to purchased capacity expense resulted entirely from changes to the  
18 estimate of capacity payment and bonus payment to AES Hawaii. There was no  
19 change from the direct testimony for capacity payments to Kalaeloa and H-  
20 POWER. For AES Hawaii, the capacity payment is based on the facility's  
21 availability. The availability was lowered because of a correction to the number  
22 of days in February 2005 (28 days vs. 29 days assumed in direct testimony). As a  
23 result, the capacity payment is reduced by \$189,000. On the other hand, the bonus  
24 payment is forecasted to increase by \$43,000 due to a slight increase in the two-  
25 year average availability and in the GNPIPD adjustment factor. Taken together,

1 the capacity payment to AES Hawaii, and for all the firm capacity independent  
2 power producers, decreased from \$108,621,000 in direct testimony to  
3 \$108,476,000. See HECO-R-507.

4 Q. What is the estimated capacity payment to AES Hawaii that is included in the  
5 2005 test year expense?

6 A. The 2005 test year estimated capacity payment to AES Hawaii is \$67,513,608.  
7 Refer to HECO-RWP-502, page 1.

8 Q. How does this compare to the actual AES Hawaii capacity expense expected to be  
9 incurred in 2005.

10 A. The actual capacity expense is expected to be higher by approximately  
11 \$2,000,000, because AES Hawaii has rescheduled its earlier planned September  
12 2005 maintenance outage to 2006, which should result in a higher availability for  
13 AES Hawaii in 2005 than the test year estimate. HECO has not revised the test  
14 year estimate, since it represents a more normalized level of capacity expense.

15  
16 CA AND DOD POSITIONS

17 Q. Please summarize the CA's position.

18 A. The CA submitted the testimony of Joseph A. Herz in CA-T-3, on pages 44-48.  
19 Mr. Herz forecasted the energy purchased by HECO during the 2005 test year at  
20 3,413.3 GWh. He forecasted an energy payment of \$260,048,000, a capacity  
21 payment of \$108,293,000, and total purchased power payment of \$368,341,000.  
22 This compares to forecasted purchased energy of 3,381 GWh, forecasted energy  
23 payment of \$189,943,000, forecasted capacity payment of \$108,621,000, and total  
24 purchased power payment of \$298,564,000 in my direct testimony. See HECO-R-  
25 503, HECO-R-505, and HECO-R-507. Thus, the CA proposed a total purchased

1 power payment which is \$69,777,000 above the amount in HECO's direct  
2 testimony.

3 Q. Why is the CA's estimate of purchased energy and purchased energy expense  
4 different from your direct testimony?

5 A. Mr. Herz stated that the purchased energy difference is due to a different amount  
6 of energy estimated to be purchased from Kalaeloa and AES Hawaii. He stated  
7 that the difference in purchased power expense is due primarily to the increase in  
8 purchase power prices as a result of the increase in fuel oil prices from the May  
9 2004 levels used in HECO's direct testimony.

10 Q. Does the CA agree with HECO's methodology in computing purchased power  
11 expenses?

12 A. The CA implies that it does not agree entirely with HECO's methodology in  
13 computing purchased energy expenses. This is HECO's conclusion after  
14 reviewing the CA's testimony and its response to HECO/CA-IR-301.

15 Q. Please elaborate.

16 A. In CA-T-3 on page 46, the CA calculated the test year energy payment to AES as  
17 \$87,446,000. This compares with HECO's calculation of energy payments of  
18 \$65,163,000 in direct testimony (see HECO-WP-503, p. 1 (Fuel + Variable O&M  
19 + Fixed O&M)), and \$65,551,000 in rebuttal testimony (see HECO-RWP-502, p.  
20 1 (Fuel + Variable O&M + Fixed O&M)).

21 In support of the table on page 46, the CA presented CA-312 to show how  
22 the \$87,446,000 energy charge amount was derived, and CA-WP-309, p. 5 to  
23 show how the fuel component of the energy charge, \$61,019,000, was derived.  
24 The CA provided a response in HECO/CA-IR-301 as to how the \$61,019,000  
25 amount was derived. It appears that the fuel component is not calculated

1 correctly, leading to an overstatement of the energy charge. (This is offset by an  
2 overstatement of ECAC revenue at present rates.)

3 Q. Does HECO agree with the CA's method of calculating the fuel component of the  
4 AES energy charge?

5 A. No. The method described by the CA in the response to HECO/CA-IR-301 is  
6 incorrect and results in an overstatement of the fuel component of the energy  
7 charge. The fuel component of the energy charge should be calculated directly  
8 using the formula in the HECO-AES Hawaii (f.k.a. AES Barbers Point, Inc.)  
9 power purchase contract ("AES contract"). (The AES contract was attached to  
10 HECO's applications for approval of the AES contract filed June 1, 1988 and  
11 August 29, 1989 in Docket No. 6177.) HECO's calculations of the fuel  
12 component of the energy charge in HECO-WP-503 and HECO-RWP-502 were  
13 based on the formula in the AES contract. The CA is incorrect in converting the  
14 energy purchased to MBtu using the AES heat rate, and multiplying the MBtus by  
15 the oil price per MBtu, because it is not a correct representation of the formula to  
16 calculate the fuel component of the energy charge.

17 Q. What is the formula for the fuel component in the AES contract, and how should it  
18 be applied in the calculation of the cost of the fuel component?

19 A. The fuel component (in July 1987 dollars) is derived from the following formula  
20 in Amendment No. 1 to the AES contract:

21 
$$\text{Fuel Cost} = \sum_{i=1}^{i=P} [(0.000061803A_i^2 - 0.0056145A_i + 2.15619) (B_i/100)]$$

22 Where:

23 A = integrated hourly load of the Facility in megawatts (rounded to the third  
24 decimal place) for each hour of the month being invoiced.

25 B = kilowatthours purchased during each specific hour of the month being

1           invoiced.

2                      $P$  = the total number of hours in the month being invoiced.

3           From the production simulation program discussed above, for each month, the

4           average megawatts (variable A) and the net megawatthours (variable B) are

5           known for the one boiler and two boiler cases. Refer to HECO-RWP-502, p. 1.

6           The fuel component on that rebuttal work paper is the sum of the fuel components  
7           of the one boiler and two boiler cases.

8           As an example, the fuel component for energy purchased in January 2005 is  
9           derived as follows:

10           Fuel component (July 1987 dollars) =  $[(0.000016803 * 180^2 - 0.0056145 * 180 +$   
11            $2.15619) * (132,581,000/100)] = \$2,240,615.$

12           Fuel component =  $\$2,240,615 * 108.479/72.465$  [3<sup>rd</sup> Q 2004 GNPIPD/Base  
13           GNPIPD] =  $\$3,354,167$ , as shown on HECO-RWP-502, p. 1.

14       Q.   Please summarize the DOD's position.

15       A.   The DOD submitted the testimony of Ralph C. Smith in DOD T-1. On Exhibit  
16           DOD-104, Mr. Smith provided an adjustment to purchased power expense of  
17           \$69,777,000 to the HECO direct testimony amount of \$298,564,000, such that the  
18           purchased power expense per DOD is \$368,341,000. Exhibit DOD-126 lists CA-  
19           101, Schedule C-4 as the reference for the \$69,777,000 adjustment.

20       Q.   Does the DOD agree with HECO's methodology in computing purchased power  
21           expenses?

22       A.   The DOD appears to have adopted the CA's position of \$69,777,000 as the  
23           adjustment to HECO's total purchased power expenses in its direct testimony.  
24           The DOD did not submit testimony to disagree with HECO's methodology in  
25           computing purchased power expenses.

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15  
16  
17  
18  
19  
20  
21  
22  
23  
24  
25

SUMMARY

- Q. Please summarize HECO's rebuttal position on power purchase expense.
- A. HECO requests recovery of \$345,434,080 of purchased power expense based on the estimate of purchased energy of 3,426 GWh during the 2005 test year. The revised estimate of purchased energy expense is \$236,958,383, and the revised estimate of purchased capacity expense is \$108,475,697.
- Q. Does this conclude your testimony?
- A. Yes.

Hawaiian Electric Company, Inc.

TOTAL PURCHASED POWER EXPENSES  
Recorded 2004 and 2005 Test Year Estimate  
In Dollars

	(a) 2004 Recorded	(b) 2005 Test Year Estimate	(c) Adjustments	(d) Revised 2005 Test Year Expense	(e) Column (d) - Column (a)	(f) Column (e) / Column (a)
Energy Payments	190,095,458	189,943,019	47,015,364	236,958,383	46,862,925	24.65%
Firm Capacity Payments	105,786,740	108,621,417	-145,720	108,475,697	2,688,957	2.54%
Total Purchase Power Expenses	295,882,198	298,564,436	46,869,644	345,434,080	49,551,882	16.75%

Totals may not add due to rounding.

Hawaiian Electric Company, Inc.

REBUTTAL TEST YEAR PURCHASED ENERGY FORECAST

	2005 Test Year (GWh)
As-available	
1. Chevron	1
2. Tesoro	6
Subtotal	7
Firm Capacity	
1. Kalaeloa	1,548
2. AES Hawaii	1,531
3. H-POWER	340
Subtotal	3,419
TOTAL TEST YEAR PURCHASED ENERGY (GWh)	3,426

Note: Totals may not add due to rounding.

Hawaiian Electric Company, Inc.

PURCHASED ENERGY FORECAST  
COMPARISON OF DIRECT AND REBUTTAL TEST YEAR

	HECO Direct (GWh)	HECO Rebuttal (GWh)	Difference (GWh)
As-available			
1. Chevron	1	1	0
2. Tesoro	6	6	0
Subtotal	7	7	0
Firm Capacity			
1. Kalaeloa	1,503	1,548	45
2. AES Hawaii	1,531	1,531	0
3. H-POWER	340	340	0
Subtotal	3,374	3,419	45
TOTAL TEST YEAR PURCHASED ENERGY (GWh)	3,381	3,426	45

Note: Totals may not add due to rounding.

Hawaiian Electric Company, Inc.

2005 TEST YEAR ENERGY EXPENSE  
(\$000)

	2005 Test Year
Kalaeloa -- Fuel	115,872
Additive	1,978
Non-Fuel	19,672
Shortfall	0
Total	137,522

Hawaiian Electric Company, Inc.

TEST YEAR ENERGY EXPENSE  
COMPARISON OF DIRECT AND REBUTTAL TEST YEAR  
(\$000)

	HECO Direct	HECO Rebuttal	Difference
Kalaeloa -- Fuel	78,817	115,872	37,055
Additive	1,920	1,978	58
Non-Fuel	19,268	19,672	405
Shortfall	0	0	0
Total	100,005	137,522	37,517
AES Hawaii -- Fuel	38,752	39,025	273
O&M	26,410	26,526	115
Total	65,163	65,551	388
H-POWER -- Energy	24,276	33,129	8,853
Other			
Chevron	53	80	27
Tesoro	447	677	230
Total	499	756	257
Total Energy	189,943	236,958	47,015

Note: Totals may not add due to rounding.

Hawaiian Electric Company, Inc.

2005 TEST YEAR FIRM CAPACITY EXPENSE

Firm Capacity Producer	Capacity Payment (\$000)
Kalaeloa	32,831
AES Hawaii	67,514
H-POWER	6,901
AES Hawaii Bonus	1,230
TOTAL	108,476

Note: Totals may not add due to rounding.

Hawaiian Electric Company, Inc.

TEST YEAR FIRM CAPACITY EXPENSE  
COMPARISON OF DIRECT AND REBUTTAL TEST YEAR

Firm Capacity Producer	Capacity Payment (\$000)		
	HECO Direct	HECO Rebuttal	Difference
Kalaeloa	32,831	32,831	0
AES Hawaii	67,702	67,514	(189)
H-POWER	6,901	6,901	0
AES Hawaii Bonus	1,187	1,230	43
TOTAL	108,621	108,476	(146)

Note: Totals may not add due to rounding.

REBUTTAL TESTIMONY OF  
AARON K. FUJINAKA

MANAGER  
OPERATIONS AND MAINTENANCE  
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Other Production O&M Expense,  
Production Inventory

1 INTRODUCTION

2 Q. Please state your name and business address.

3 A. My name is Aaron Fujinaka. My business address is 475 Kamehameha Highway,  
4 Pearl City, Hawaii.

5 Q. Mr. Fujinaka, have your previously submitted testimony in this proceeding?

6 A. Yes. I submitted written direct testimony, exhibits, and supporting workpapers as  
7 HECO T-6.

8 Q. What is the scope of your rebuttal testimony?

9 A. My rebuttal testimony will:

- 10 1) present HECO's rebuttal position with respect to Other Production  
11 Operation and Maintenance ("O&M") expense, and the Production  
12 Materials Inventory,  
13 2) address the areas of agreement and disagreement between HECO and the  
14 Consumer Advocate ("CA"),  
15 3) address the areas of agreement and disagreement between HECO and the  
16 Department of Defense ("DOD").  
17

18 HECO REBUTTAL POSITION

19 Q. What is HECO's rebuttal position with respect to Production O&M Expense?

20 A. HECO's revised test year estimate of Production O&M Expense is \$56,497,000;  
21 \$23,638,000 for Operation Expense and \$32,859,000 for Maintenance Expense.  
22 (See HECO-R-601.) This is a \$1,456,000 increase from the \$55,041,000 estimate  
23 of test year Production O&M Expense presented in direct testimony. Production  
24 Operation Expense has decreased by \$239,000. Production Maintenance has  
25 increased by \$1,695,000.

1     Production Operation Expense

2     Q.   What is HECO's revised test year estimate of Production Operation – Labor and  
3         Nonlabor Expense?

4     A.   HECO's revised test year estimate of Production Operation – Labor and Nonlabor  
5         Expense is \$23,638,000; \$13,398,000 for Labor and \$10,240,000 for Nonlabor.  
6         (See HECO-R-602.)

7     Q.   What revisions to the Production Operation – Labor Expense have been made  
8         since the filing of direct testimony?

9     A.   Production Operation – Labor expense of \$13,398,000 remains unchanged from  
10         direct testimony.

11    Q.   What revisions to the Production Operation – Nonlabor Expense have been made  
12         since the filing of direct testimony?

13    A.   Production Operations – Nonlabor expense was reduced by \$239,000 as a result of  
14         additional adjustments reflected in HECO's May 5th, Update Letter and CA-IR-  
15         641; HECO's response to CA-IR-664 and DOD/HECO 6-13; and additional  
16         rebuttal adjustments. (See HECO-R-603.)

17    Q.   Please explain the adjustments in Production Operations – Nonlabor as stated in  
18         HECO's May 5<sup>th</sup> Update Letter and CA-IR-641.

19    A.   As summarized in HECO-R-603, three adjustments were made to Production  
20         Operations – Nonlabor.

- 21         1)   Reduction of \$62,000 for the removal of Combined Heat and Power (CHP)  
22             related expenses;
- 23         2)   Addition of \$98,000 for Substation Distributed Generation (DG) Operation  
24             Nonlabor expenses; and
- 25         3)   Reduction of \$75,000 for Sun Power for Schools.

1 Q. What adjustments have been made to Other Production Operation – Nonlabor in  
2 HECO's response to CA-IR-664?

3 A. Referring to HECO-R-603, Operation – Nonlabor expense is reduced by \$101,000  
4 for lower Kahe water consumption expenses.

5 Q. What adjustments have been made to Other Production Operation – Nonlabor in  
6 HECO's response to DOD/HECO 6-13?

7 A. Referring to HECO-R-603, Operation – Nonlabor expense is reduced \$75,000 for  
8 the removal of outside services relating to a Purchase Power Tolling Arrangement  
9 Study.

10 Q. What additional adjustments Production Operations – Nonlabor are being  
11 proposed in rebuttal?

12 A. As summarized in HEOC-R-603, two adjustments are being proposed.

13 1) Reduction of \$20,000 for EPRI R&D expenses from \$500,000 to \$480,000.

14 2) Reduction of \$4,000 for Operation Nonlabor Ellipse expenses.

15 Q. Are there any other adjustments to Production Operation Expense being proposed  
16 in rebuttal?

17 A. No.

18 Production Maintenance Expense

19 Q. What is HECO's revised test year estimate of Production Maintenance – Labor and  
20 Nonlabor Expense?

21 A. HECO's revised test year estimate of Production Maintenance – Labor and  
22 Nonlabor Expense is \$32,859,000; \$12,372,000 for Labor and \$20,487,000 for  
23 Nonlabor. (See HECO-R-602.)

24 Q. What revisions to the Production Maintenance – Labor Expense have been made  
25 since the filing of direct testimony?

1       A.   Production Maintenance – Labor expense of \$12,372,000 remains unchanged  
2       from direct testimony.

3       Q.   What revisions to the Production Maintenance – Nonlabor Expense have been  
4       made since the filing of direct testimony?

5       A.   Production Maintenance – Nonlabor expense was increased by \$1,695,000 as a  
6       result of additional adjustments reflected in HECO's May 5th Update Letter, CA-  
7       IR-641, and additional rebuttal adjustments. (See HECO-R-604.)

8       Q.   What adjustments have been made to Production Maintenance – Nonlabor in  
9       HECO's May 5<sup>th</sup> Update Letter and CA-IR-641?

10      A.   As summarized in HECO-R-604, three adjustments were made to Other  
11      Production Maintenance – Nonlabor.

12           1)   Reduction of \$157,000 for the removal of CHP maintenance related  
13           expenses;

14           2)   Addition of \$490,000 for a Betterment accounting adjustment approved by  
15           the Commission

16           3)   Addition of \$1,305,000 for Substation DG Maintenance Nonlabor expenses.

17      Q.   What additional adjustments to Production Maintenance – Nonlabor are being  
18      proposed in rebuttal?

19      A.   Referring to HEOC-R-604, two adjustments are being proposed.

20           1)   Addition of \$63,000 to reflect higher Substation DG Maintenance Nonlabor  
21           expense estimates.

22           2)   Reduction of \$6,000 for Maintenance Nonlabor Ellipse expenses.

23      Q.   Are there any other adjustments to Production Maintenance Expense being  
24      proposed in rebuttal?

25      A.   No.

1 Q. Please summarize HECO's rebuttal position on Other Production O&M expense.

2 A. HECO's rebuttal position is \$1,456,000 higher than the 2005 test year estimate in  
3 HECO T-6, or \$56,497,000.

4 Production Materials Inventory

5 Q. What is HECO's rebuttal position related to Production Materials Inventory?

6 A. HECO's revised test year Production Materials Inventory value is \$5,176,000 as  
7 shown in HECO-R-605, page 2.

8 Q. How does this amount compare with the Production Materials Inventory proposed  
9 in HECO-628?

10 A. The \$5,176,000 amount is lower than the \$5,329,000 direct testimony amount.

11 Q. How does this inventory value compare to the CA's proposed adjustment to  
12 Production Materials Inventory?

13 A. This inventory value agrees with the CA's proposed inventory as HECO accepts  
14 the CA's proposed inventory value.

15 Q. How did the CA derive the proposed Materials Inventory?

16 A. The CA proposed a total increase in Materials Inventory (Power Supply and  
17 T&D) of \$123,000 over the Test Year average of \$9,984,000. This is shown in  
18 Exhibit CA-101, Schedule B, page 2, under column (C) on line 7.

19 Q. How did the CA determine the \$123,000 increase in Materials Inventory?

20 A. Referring to CA-T-1, page 97, lines 14-17, "Materials & Supplies inventories  
21 supportive of Production Department and T&D functions were updated using the  
22 December 31, 2004 actual inventory balances provided in response to CA-IR-95,  
23 page 3, in place of the Company's estimated balances." Referring to Exhibit CA-  
24 101, Schedule B-2, page 1 of 1, lines 1-5, the CA used the updated 12/31/04 Test  
25 Year Beginning amount of \$10,425,000 and averaged that with the 12/31/05 Test

1 Year End amount of \$9,789,000 to derive the Test Year Average amount of  
2 \$10,107,000. The increase in Materials Inventory of \$123,000 is the difference  
3 between the Test Year average of \$10,107,000 and the 12/31/05 Test Year End  
4 amount of \$9,789,000.

5 Q. What is the Production portion of this increase and what is the resulting Average  
6 Inventory Value for the 2005 test year?

7 A. The Production portion of this increase is \$39,000. The resulting Production  
8 Average Inventory Value for the 2005 test year is \$5,176,000. Please refer to  
9 HECO-R-605, pages 1-3, for the derivation of these amounts.

10 Q. What is HECO's position regarding the proposed increase?

11 A. As stated earlier, HECO agrees with the CA on their proposed increase to the  
12 Production Material Inventory value based on the 12/31/04 actual value.

13  
14 AREAS OF HECO-CA AGREEMENT AND DISAGREEMENT

15 Q. What is the CA's position with respect to Production O&M Expense?

16 A. The CA's proposal for Production O&M Expense is \$51,869,000; \$22,094,000 for  
17 Operations Expense and \$29,776,000 for Maintenance Expense. (See HECO-R-  
18 606)

19 Q. How does the CA's proposed adjustments compare with HECO's test year  
20 Production O&M expenses in direct testimony?

21 A. The CA's proposed Production O&M of \$51,869,000 is \$3,172,000 less than  
22 HECO's test year Production O&M of \$55,041,000.

23 Q. How was the downward adjustment of \$3,172,000 derived?

24 A. The downward adjustment was the result of a reduction of Production Operation  
25 expense by \$1,784,000 and a reduction of Production Maintenance expense by

1           \$1,388,000.

2           Q.    What makes up the reduction amounts?

3           A.    The components of the reduction of \$1,784,000 in Production Operation expense  
4           is detailed in HECO-R-607. The components of the reduction of \$1.388,000 in  
5           Production Maintenance expense is detailed in HECO-R-608.

6           Q.    How does the CA's proposed adjustments compare with HECO's rebuttal estimate  
7           for Production O&M of \$56,497,000?

8           A.    The CA's proposed Production O&M of \$51,869,000 is \$4,628,000 less than  
9           HECO's rebuttal Production O&M of \$56,497,000.

10          Q.    In what areas are HECO and the CA in agreement?

11          A.    HECO and the CA agree on a net increase to Other Production O&M – Nonlabor  
12          expense of \$19,000.

13          Q.    What is the net increase of \$19,000 comprised of?

14          A.    The net increase is comprised of a reduction of \$314,000 in Other Production  
15          Operations – Nonlabor expenses, and an increase of \$333,000 in Other Production  
16          Maintenance – Nonlabor expenses. The net impact of the two amounts to an  
17          increase of \$19,000.

18          Q.    Please discuss the reduction of \$314,000 in Other Production Operations –  
19          Nonlabor expenses that are in agreement with HECO and the CA.

20          A.    The \$314,000 reduction in Other Production Operations – Nonlabor expenses is  
21          comprised of a reduction of \$101,000 for Kahe water expense (Exhibit CA-101,  
22          Schedule C-8, page 1, line 5), a reduction of \$63,000 for the removal of CHP  
23          operations related expenses (Exhibit CA-101, Schedule C-6, page 1, line 11),  
24          removal of Sunpower for School expense of \$75,000 (Exhibit CA-101, Schedule  
25          C-8, page 1, line 17); and the removal of \$75,000 for Purchase Power Tolling

1 Study expenses (Exhibit CA-101, Schedule C-8, page 1, line 26).

2 Q. Please discuss the increase of \$333,000 in Other Production Maintenance –  
3 Nonlabor expenses that are in agreement with HECO and the CA.

4 A. The \$333,000 increase in Other Production Maintenance – Nonlabor expenses is  
5 comprised of a reduction of \$157,000 for the removal of CHP maintenance related  
6 expenses (Exhibit CA-101, Schedule C-6, page 1, line 12), and an increase of  
7 \$490,000 for a Betterment accounting adjustment approved by the Commission  
8 (Exhibit CA-101, Schedule C-9, page 1, line 13).

9 Q. Are there other areas of agreement between HECO and the CA?

10 A. Yes, HECO and the CA are in agreement with the CA's proposed adjustments to  
11 Production Material Inventory as discussed above.

12 Q. Is there a difference between HECO's rebuttal position for Other Production  
13 Operation and Maintenance Expenses and the Consumer Advocate's proposed  
14 Other Production Operation and Maintenance Expenses regarding the Standard  
15 Labor Rate Adjustment?

16 A. Yes. HECO-R-607 shows a \$50,000 Standard Labor Rate Adjustment proposed  
17 by the CA for Production Operation Expenses and HECO-R-608 shows a \$46,000  
18 Standard Labor Rate Adjustment proposed by the CA for Production Maintenance  
19 Expenses. As discussed by Ms. Faye Yamauchi in HECO RT-13, HECO, the  
20 Consumer Advocate and the DOD are in agreement with the Standard Labor Rate  
21 Adjustment. HECO is reflecting the adjustment as a separate line item in the  
22 results of operations. The Consumer Advocate attempted to allocate the total  
23 adjustment to each block of accounts. (The DOD reflected the entire amount in  
24 A&G expenses.) HECO's Other Production O&M Expense estimate, if reduced  
25 by the amount of the CA's proposed allocation of the Standard Labor Rate

1 Adjustment, would be \$56,401,000.

2 Q. In what areas are HECO and the CA in disagreement?

3 A. The CA proposes additional adjustments in Other Production O&M - Labor and  
4 Nonlabor which results in significant reductions that will negatively impact  
5 HECO's ability to adequately fund critical operations and maintenance of its  
6 generating units and facilities.

7 Q. Specifically what additional adjustments are in disagreement between HECO and  
8 the CA?

9 A. In Other Production Operations, the CA proposes to reduce Labor expenses by  
10 \$278,000, and Nonlabor expenses by \$1,192,000. In Other Production  
11 Maintenance, the CA proposes to reduce Labor expenses by \$1,249,000, and  
12 Nonlabor expenses by \$472,000.

13 Q. How did the CA derive the reduction in Operations Labor and Maintenance Labor  
14 expenses?

15 A. The CA utilized a methodology that averaged the 2005 test year employee count  
16 with the year end actual employee count as of December 31, 2004.

17 Q. Does HECO agree with the CA's averaging methodology?

18 A. No, HECO does not.

19 Q. Please explain the CA's method for "averaging" labor expenses for Other  
20 Production O&M.

21 A. The CA argues that HECO should not be permitted to include in the 2005 test year  
22 the annual expenses for positions that were not filled for the entire year of 2005.  
23 The CA took the number of positions that were filled as of January 1, 2005, and  
24 positions that were included in the 2005 test year staffing count, and averaged the  
25 two numbers. After computing the average, the CA computed the difference

1           between the 2005 test year employee count and the averaged employee count, and  
2           then divided the difference by the 2005 test year count to arrive at an "adjustment  
3           percentage" which the CA used to reduce the 2005 test year labor expense for  
4           Other Production O&M. Please refer to CA-T-1, page 61-62, and CA-WP-101-  
5           C8/9 for the details of the CA's method.

6           Q.   What is HECO's 2005 test year employee count for Other Production O&M.

7           A.   As stated in my direct testimony, T-6, the 2005 test year employee count for Other  
8           Production O&M is 354.

9           Q.   How many of the positions in the 2005 test year staffing count for Other  
10          Production O&M were not filled as of the beginning of 2005.

11          A.   Other Production O&M had 310 filled positions and 44 unfilled positions. Please  
12          refer to CA-IR-48, page 15.

13          Q.   How were the unfilled positions treated under the CA's proposed "averaging"  
14          method?

15          A.   Because those positions were not filled as of the beginning of 2005, they were not  
16          included in the CA's position count for the beginning of 2005.

17          Q.   Is the CA's proposed "averaging" method reasonable?

18          A.   No. First, most of the staffing increase is for new positions, and is not just to fill  
19          previously authorized but unfilled positions. In Production, HECO needs to add

1           In addition, new rates are not being set at the beginning of 2005. If rates  
2           were reset at the beginning of the year, and it was assumed that full staffing was in  
3           place at the beginning of the year even though staffing increases occurred  
4           gradually over the course of the year, then the amount included for staffing in  
5           rates for 2005 (looked at in isolation) might be too high. In this case, however,  
6           rates are not expected to be reset until at least October (for the interim increase)  
7           and until next year (for the final increase). HECO will not have received any rate  
8           increase during the first 9 months of 2005, even though significant staff increases  
9           have been made.

10           Moreover, staffing expenses should not be viewed in isolation, particularly  
11           in the Production area where the CA proposes the largest adjustment. As shown  
12           in HECO RT-6, and numerous IR responses, the Production expenses are  
13           expected to exceed the 2005 rate case [budget] amounts, even though there has  
14           been a "lag" in filling some of the new positions, and even though there have been  
15           some vacancies in existing positions.

16       Q.   Does the CA contest the need for the staffing increases?

17       A.   In general, no. For instance, in direct testimony, CA witness T-1 conceded that  
18           "some need for increased operations staffing exists" to reduce overtime for Other  
19           Production Operations. T-1, page 55, lines 14-24.

20       Q.   The CA faults HECO's proposed staffing increase because "Notably absent from  
21           this major staffing buildup is any significant reduction in HECO's historically  
22           high overtime rates...." Is that a fair statement?

23       A.   No. Overtime is not reduced in direct proportion to an increase maintenance  
24           staffing forecasted in 2005 because the maintenance staffing levels forecasted  
25           were based on the numbers of specific trades and craft personnel required to keep

1 up with anticipated increased workload requirements. Comparing the 2005 test  
2 year forecasted overtime percentages with actual historical trends indicates a  
3 decrease in overtime percentage for each of the Maintenance RA's. Most affected  
4 are the Waiau and Kahe Maintenance crews with the establishment of the night  
5 shift maintenance crews. It should be noted that actual overtime is not only a  
6 function of staffing levels, but also a function of work requirements to keep  
7 available units operational and in compliance (environmental, safety, permit) on a  
8 24x7 basis. Also, units down for overhaul, maintenance outages or forced outages  
9 contribute to overtime trends as work is done on weekends, holidays after normal  
10 business hours, and on a call out basis. Unit outages are also overlapped, or  
11 stacked, to accomplish normal and recurring maintenance. During periods when  
12 labor shortfalls occur, such as when unit outages are stacked, man-hour deficits  
13 are made up with overtime and/or contract services. System demand is expected to  
14 continue to increase into the foreseeable future and will result in reduced  
15 generating reserve margins. This will tend to increase overtime as all available  
16 time and resources are utilized to provide reliable service. Please refer to HECO's  
17 response to CA-IR-48.

18 Q. What is the current employee count for Other Production O&M?

19 A. Referring to HECO-R-609, as of June 30, 2005, Other Production O&M had 307  
20 filled positions and 47 unfilled positions.

21 Q. Does HECO intend to fill all of the 47 remaining vacancies in 2005?

22 A. Yes. Necessary approvals have been obtained from management to fill all of the  
23 open positions in 2005 and HECO is continuing to try to fill all of the vacant  
24 positions.

25 Q. What is the status of the hiring process for these unfilled positions?

1 A. The status of the hiring process for each open position is summarized in HECO-R-  
2 609.

3 Other Production Operations – Labor and Nonlabor

4 Q. What comprises the CA's proposed reduction to Other Production Operations -  
5 Labor expense by \$278,000?

6 A. The CA's proposed reduction of \$278,000 to Other Production Operations Labor  
7 expenses is summarized in HECO-R-607, lines 1 through 3, and is comprised of a  
8 reduction of \$218,000 based on the CA's method of normalizing labor costs (CA-  
9 WP-101-C8/9), a reduction of \$50,000 for the Operations portion of standard rate  
10 overtime pay, discussed earlier in my rebuttal testimony (Exhibit CA-101,  
11 Schedule C, page 4, column C20), and a reduction of \$10,000 for the Operations  
12 portion of hiring lag (Exhibit CA-101, Schedule C21, page 1, column (E), line 2).

13 Q. What is HECO's position with regard to the CA's proposal to reduce Other  
14 Production Operation – Labor by \$278,000?

15 A. HECO disagrees with the CA's proposal on the basis that the primary increase in  
16 Production Operation – Labor expenses (HECO T-6, page 23) is due to the need  
17 to increase Operator staffing in order to staff extra shifts (increase unit availability  
18 from 16x5 to 24x7) on Waiau Units 3&4 and Honolulu Units 8&9. All other  
19 HECO generating units at Waiau and Kahe are currently staffed to support 24x7  
20 operation.

21 Q. How many positions are included in HECO's 2005 test year estimate for the four  
22 responsibility areas (RA's) that make up the Operating Division?

23 A. HECO's 2005 test year estimate for headcount in the Operating Division RA's is  
24 147.

25 Q. Please describe how these positions are divided among the departments or units in

1 Operating Division.

2 A. The total of 147 is divided among the four RA's in Operating Division as shown  
3 below:

4	<u>Responsibility Area</u>	<u>Test Year Staffing Level</u>
5	IK (Kahe)	58
6	IW (Waiau)	62
7	IH (Honolulu)	26
8	IO (Operations Admin)	<u>1</u>
9	Total	147

10 Q. What was the actual staffing count for Operating Division as of December 31,  
11 2004?

12 A. Production Operations had 145 filled positions and 2 open positions. The total of  
13 145 is divided among the four RA's in Operating Division as shown below:

14	<u>Responsibility Area</u>	<u>Staffing Level as of 12/31/04</u>
15	IK (Kahe)	59
16	IW (Waiau)	64
17	IH (Honolulu)	19
18	IO (Operations Admin)	<u>3</u>
19	Total	145

20 Q. Were there any new positions among the 145 that were filled as of the end of  
21 2004?

22 A. Yes. The Operator staffing at Waiau Station was increased from 46 at the end of  
23 August 2004 to 55 at the end of December 2004 to support the change in  
24 operation of Waiau units 3&4 and Honolulu units 8&9 from 16 hours a day, 5  
25 days a week, to 24 hours a day, 7 days a week. The staffing at Honolulu Station

1 was also increased from 12 to 14 at the end of December 2004.

2 Q. Were there any other changes to Operator staffing?

3 A. Yes. Staffing level was increased again to achieve an Operator staffing level of  
4 53 at Waiau Station in March 2005 and 19 at Honolulu Station in June 2005. The  
5 transition from 16X5 to 24X7 operation was completed for Waiau Units 3&4 in  
6 March and for Honolulu 8&9 in June. The overall net increase in staffing was 7 at  
7 Waiau and 7 at Honolulu.

8 Q. What were these employees doing prior to the completion of the transition to 24x7  
9 operations of Waiau Units 3&4 and Honolulu Units 8&9?

10 A. These employees were in training. The Operator training program consists of 12  
11 weeks of classroom and on-the-job training where the Equipment Operator  
12 Trainee learns system fundamentals and the operating details for the plant and  
13 equipment. During the 12 weeks, the Operator Trainee will perform proficiency  
14 demonstrations on the essential duties of the position. This is followed by 4  
15 weeks of performing the watch-standing duties of the Equipment Operator on his  
16 or her own. Upon successful completion of the training program, the Trainee is  
17 promoted to Equipment Operator.

18 Q. What is HECO's position regarding the CA's proposed reduction of \$10,000 for

---

19 the Operations portion of hiring lag (Exhibit CA-101, Schedule C21, page 1,  
20 column (E), line 2)?

21 A. As mentioned earlier in this rebuttal testimony, HECO opposes the adjustment. In  
22 looking at the overall actual Production O&M expenses for 2005, it is apparent  
23 that the actual expenses will exceed the 2005 test year estimates. In these  
24 circumstances, the CA's proposed hiring lag adjustment is not reasonable.

25 Q. What comprises the CA's proposed reduction to Other Production Operations –

1 Nonlabor expenses by \$1,050,000?

2 A. The CA's proposed reduction of \$1,300,000 is comprised of adjustments to reduce  
3 Emissions Fees by \$69,000; remove Electric Shock Absorber R&D expenses of  
4 \$500,000; and reduce Kahe 7 Amortization costs by \$731,000. Each Other  
5 Production Operations - Nonlabor area is discussed separately below.

6 Emissions Fees

7 Q. What is the CA's position on Emissions Fees?

8 A. The impact to Other Production Operation – Nonlabor expense of the CA's  
9 Emission Fee proposal is a reduction of \$69,000. The CA justifies their proposal  
10 in CA-T-1, pages 68 – 70.

11 Q. What is the basis for the CA's proposal?

12 A. The CA contends that the test year estimate should reflect the most recent trend  
13 and selects the past 5 years when 12 years of actual historical data exists. The  
14 CA further speculates on the reasons for issuing or not issuing waivers based on  
15 the CA's response to HECO/CA-IR-110. HECO doesn't agree with the CA's  
16 method of determining a normalized value for emission fees when well-defined  
17 historical data exists.

18 Q. What is HECO's position on regarding the expense for emission fees?

19 A. HECO has presented a broader-based method for determining a normalized  
20 emission fee that takes into account 12 years of actual data as set forth in HECO's  
21 response to CA-IR-183, page 2, and as explained in my direct testimony, T-6.

22 Electronic Shock Absorber

23 Q. What issues has the CA raised with respect to the ESA development funds?

24 A. The CA recommended that costs incurred prospectively for ESA development be  
25 deferred as a regulatory asset, net of any royalties or other income received, for

1 consideration and possible rate recovery in future regulatory proceedings.

2 Q. Did the CA offer another option for the ESA development funds?

3 A. Yes. CA stated that if the Commission disagreed with the CA's proposed deferral  
4 and possible future recovery, an alternative option would be to allow only  
5 \$121,000 (based on HECO anticipated payments in 2005).

6 Q. Does HECO agree with the CA's proposal or option?

7 A. HECO agrees with the CA's option to allow \$121,000 for 2005 ESA  
8 development, but seeks flexibility in the use of the remaining funds in other  
9 research and development ("R&D") projects. HECO's expenditures for R&D  
10 activities could increase in the future so the test year level of expenses might  
11 actually understate the on going level of expenses for this type of activity. In  
12 order to meet the requirements of the current Renewable Portfolio Standards law  
13 and growing customer needs, new types of technologies will have to be explored  
14 and developed.

15 HECO is positioning itself to be even more proactive in the advancement  
16 of other new technologies and assessment of revolving and evolving energy  
17 policies. Only by assessing the next steps and next technologies through research,  
18 development and demonstration (RD&D) can HECO implement new generation  
19 technologies and enhance its ability to provide efficient, reliable service to its  
20 customers. Activities to position HECO in the long-term (NARIIC 021) would

---

21 include, but would not be limited to, hydrogen energy, fuel cells, advanced energy  
22 storage systems, technology related to utility activities and enhancements to  
23 demand-side management for peak shaving, reliability, etc., improved customer  
24 relations, long-term planning, and other emerging technologies. Some of the state

metering, system benefit charges, protecting the environment, reducing impact on  
customer rates, energy security, carbon emissions, energy credit trading, tax  
credits, and other energy policies.

4 Q. How does HECO plan to spend the remaining ESA funds for R&D projects?

5 A. HECO plans to spend the remaining ESA funds in 2005 for the following projects:

- 6 • Testing and characterization of a 1 kW liquefied petroleum gas (“LPG”)
- 7 reforming unit designed for residential use
- 8 • Stationary sodium-sulfur (“NaS”) battery energy storage
- 9 • Performance assessment of emerging photovoltaic (“PV”) technology
- 10 • Research and development of a new communication technology for advanced
- 11 meter and customer outage detection devices

12 1 kW LPG Reformer Project

13 Q Can you provide a summary on the 1 MW TDC reformer project?

14       A.   While the majority of fuel cell tests on the mainland and abroad are with natural  
15       gas, there is strong interest in other fuel sources such as propane. Japan's Osaka  
16       Gas Company has developed a LPG reformer for residential application. A 1 kW  
17       LPG or propane fueled reformer, designed for residential use, will be purchased,

1           technology is to have a presence in Hawaii propane may be the fuel of choice.  
2           Reforming the propane to a hydrogen rich gas is needed for fuel cell operation.  
3           Thus understanding the operation of the reformer and characterizing the fuel from  
4           the reformer to the fuel cell become important steps in the development of fuel  
5           cells in Hawaii.

6       Q.    Can you provide the cost estimate for this project?

7       A.    The cost estimate is about \$100,000.

8       Q.    Does HECO have any signed agreements?

9       A.    No, not at this time. A draft agreement has been sent to HECO legal department  
10           for review. After this review, a copy will be forwarded to HNEI for review and  
11           final signature. HECO is in communication with HNEI personnel on the  
12           contractual agreement and hopes to sign the agreement in a few weeks.

13      Q.    What are the future activities for this project?

14      A.    If the initial work is successful, follow-on work over several years could include  
15           the evaluation of the reformer using controlled, time variant, fuel blends  
16           representative of full and empty tanks gas compositions, evaluation of reformer  
17           performance using bottled, engine-grade LPG, evaluation of the reformer  
18           connected to a proton exchange membrane fuel cell (PEMFC) operating on LPG  
19           gas and long-term monitoring of performance and operation, and maintenance  
20           requirements for a PEMFC operating on LPG.

21      NaS Battery Energy Storage Project

22      Q.    Can you provide a summary on the stationary NaS battery energy storage project?

23      A.    HECO's R&D project will focus on the stationary NaS battery energy storage  
24           system ("BESS"). NaS is an advanced electrochemical storage system that was  
25           co-developed by the Tokyo Electric Power Company and NGK Insulators, Ltd.

1 after decades of persistent development. The NaS system has not been  
2 demonstrated in any commercial applications in the United States. Without

confirmation of the long-term performance and viability of the advanced BESS,  
utilities will be reluctant to purchase them. Further detailed information on NaS  
and BESS technology was published in the October 2004 report entitled “HELCO  
Operational Issues – Bulk Energy Storage”, which was co-authored by SENTECH

1           A number of advanced batteries are finally reaching commercial prototype  
2 stages, but there is very little information on the long-term performance of these  
3 systems in real-life utility applications. Validation of performance is needed  
4 before the technology is able to enter widespread use in the United States. In turn,  
5 wider use will drive the cost of BESS systems down to a more economic level.

6       Q. Can you provide the cost estimate for this project?

7       A. HECO's cost share in the NaS BESS project is \$50,000 from this budget (total  
8 project cost is about \$3.5 million).

9       Q. What is the status of this project?

10      A. HECO is working with EPRI on an agreement and hopes to sign the agreement in  
11 a few weeks.

12      Q. What are the future activities for this project?

13      A. The project will commence this summer with design and engineering of the  
14 BESS. The NaS BESS will be installed in mid-2006 and tested through 2008.  
15 The demonstration program is expected to last 18-24 months and is a collaborative  
16 effort with New York Power Authority, Long Island Power Authority, Department  
17 of Energy, Electric Power Research Institute ("EPRI"), and the New York State  
18 Energy Research and Development Agency.

19           If successful, follow-on work could include the installation of a small unit  
20 for testing and evaluation on the local electrical grid as an option to shift the

1       A.    As a participant, HECO will receive all technical reports, monthly construction  
2           reports, installation and commissioning reports, quarterly and final reports and can  
3           attend the semi-annual technical meetings. As an EPRI member, HECO could  
4           only receive the final report.

5       Performance Assessment of Emerging PV Technology Project

6       Q.    Can you provide a summary of the performance assessment of emerging PV  
7           technology project?

8       A.    Sunpower Corp., a majority-owned subsidiary of Cypress Semiconductor Corp.,  
9           designs and manufactures silicon solar cells using a novel design, all-back-  
10          contact, whereby the metal contacts that collect and conduct electricity are on the  
11          back surface of the cell (versus the front in standard PV cells). This improves cell  
12          performance by eliminating the surfaces that block out sunlight and adds aesthetic  
13          appeal by eliminating reflective contacts, and thus allowing the cells to be  
14          uniformly dark. Module efficiency is reported to be 17% (highest of available  
15          modules). Sunpower's all-back-contact design achieves a well-established  
16          performance advantage over gridded cells. There are other approaches used today  
17          that can lay a similar claim, but the jury is still out on which one will have the  
18          lowest cost in large-scale manufacturing.

19                HECO will conduct a multi-phase project to verify in-field performance  
20                and conversion efficiencies of SunPower's all-back-contact PV modules. A side-  
21                by-side comparison with standard single-crystalline PV modules would help  
22                HECO assess performance claims.

23                In 2005, HECO will purchase and install (time permitting) the PV modules  
24                and balance of plant equipment on a HECO or alternative site. HECO will also  
25                contract with HNEI to develop the instrumentation and methodology for data

1 monitoring.

2 Q. Why is this new R&D project necessary?

3 A. Traditional single-crystalline PV cell efficiency (13 percent to 14 percent) and  
4 poly-crystalline PV cell efficiency (11 percent to 12 percent) have the electrical  
5 collector wires in the face or front of the PV modules. The higher efficient PV  
6 module is an improvement over the traditional PV modules since the electrical  
7 collector wires are on the back of the PV modules, thus more sunlight is hitting  
8 the PV cells. Increasing cell efficiency will mean less PV panels and less space

1 efficient PV modules with conventional PV modules.

2                    If these PV modules are truly more efficient than the conventional single  
3                    crystalline silicon PV modules, HECO hopes to use these types of PV modules in  
4                    future PV installations.

5 New Communications Technology for Advanced Meter  
6 and Customer Outage Detection Project

7 Q. What is HECO doing to research and develop new communication technology for  
8 advanced meter and customer outage detection devices?

9       A.   As explained in the rebuttal testimony of Alan Hee, RT-10, HECO will work with  
10       engineering manufacturers to develop and demonstrate prototypes of customer  
11       and grid data collection/communication devices.

12.            Can you provide the next estimate for this segment?

13       A.     The project cost is about \$180,000 for 2005.

14 Q. What is the new total for the Electronic Shock Absorber and research and  
15 development projects listed above?

16       A.   The total proposed by HECO is \$480,000. This total is a reduction from the  
17       \$500,000 presented in direct testimony and is reflected in HECO-R-603 as a

1 \$1,575,000 and at 12/31/05 is projected to be only \$675,000, yet HECO has  
2 included \$900,000 in annual expenses in the test year of its amortization.” The  
3 CA proposes in CA Adjustment Schedule C-8, lines 21-24, to effectively  
4 reschedule the remaining unamortized cost as of December 31, 2004, over a four  
5 year period during which rates established in this Docket are presumed to remain  
6 in effect.

7 Q What is HECO's position with regard to the \$721,000 for Volo 7 Amendment

8 expense.

9       A.   HECO's position on the CA's proposed rescheduling of the remaining  
10       unamortized cost as of December 31, 2004 is explained by Ms. Faye Yamauchi in  
11       HECO RT-13, pages 19-22.

1     Ellipse Expenses

2     Q.    What is the CA's position with regard to Ellipse expenses?

3     A.    Referring to Exhibit CA-101 Schedule C-14, page 1, footnote (d), the CA  
4           combines Ellipse upgrade and buy-down costs and proposes to reduce Other  
5           Production O&M – Nonlabor expense relating to Ellipse expenses by a total of  
6           \$68,000; \$34,000 in Other production Operations – Nonlabor and \$34,000 in  
7           Other Production Maintenance – Nonlabor.

8     Q.    What is HECO's position with regard to the CA's proposed reductions to Ellipse  
9           related costs totaling \$68,000?

10    A.    HECO disagrees with the CA's proposal. As mentioned earlier in my rebuttal  
11           testimony, RT-6, and as shown on HECO-R-603 and HECO-R-604, HECO  
12           proposes a reduction to Ellipse expenses for Production O&M in the amount of  
13           \$10,000. Please refer to testimony by Ms. Fay Yamauchi in HECO RT-13, for  
14           HECO's position on the treatment of Ellipse upgrade and buy-down costs.

15    Q.    Please summarize the items that have not reached agreement between HECO and  
16           the CA on Other Production Operations – Labor and Nonlabor expenses.

17    A.    HECO-R-610 compares HECO's rebuttal position with the CA's proposed  
18           adjustments to Other Production Operations – Labor and Nonlabor.

19    Other Production Maintenance O&M

20    Q.    What comprises the CA's proposed reduction to Other Production Maintenance -  
21           Labor expense by \$1,249,000?

22    A.    The CA's proposed reduction of \$1,294,000 to Other Production Maintenance  
23           Labor expenses is comprised of a reduction of \$1,194,000 based on the CA's  
24           method of normalizing labor costs (CA-WP-101-C8/9), a reduction of \$46,000 for  
25           the Maintenance portion of standard rate overtime pay (Please refer to the rebuttal

1 testimony of Fay Yamauchi, RT-13) (Exhibit CA-101, Schedule C, page 4,  
2 column C20), and a reduction of \$9,000 for the Maintenance portion of hiring lag  
3 (Exhibit CA-101, Schedule C21, page 1, column (E), line 2).

4 Q. What is HECO's position with regard to the CA's proposal to reduce Other  
5 Production Maintenance – Labor by \$1,249,000?

6 A. HECO disagrees with the CA's proposal on the basis that the primary increase in  
7 Other Production Maintenance – Labor expenses is due to additional trades and  
8 cost staffing needed to establish right-of-way maintenance. HECO T-6

9 29 - 30, HECO 608, 609, 623, 624, CA-IR-43, 45, 46, 48), to support additional  
10 operational maintenance during off-peak periods as part of Production's capacity

1	Total	160
---	-------	-----

2 Q. What was the actual staffing count for Maintenance Division as of December 31.

3 2004?

4       A.   Maintenance Division had 128 filled positions and 32 open positions. The total of  
5       128 is divided among the four RA's in Operating Division as shown below:

6	<u>Responsibility Area</u>	<u>Staffing Level as of 12/31/04</u>
---	----------------------------	--------------------------------------

7 IL (Kahe) 27

8	IM (Maintenance Admin)	2
---	------------------------	---

9 IN (Honolulu) 8

10	IT (Travel)	66
----	-------------	----

11 IX (Waiau) 25

12	Total	128
----	-------	-----

13 Q. What accounts for the difference of 32 positions between the 2005TY forecast  
14 staffing level and at 12/31/04?

15       A.   20 of those positions are additional trades and crafts and supervision to establish a  
16       nightshift maintenance crew.

17 Q. What accounts for the remaining 12 vacancies?

18       A.   The 12 remaining vacancies are primarily the result of transitional causes such as  
19       retirement, transfers, and/or terminations.

20 Q. What is the status of the hiring process for the 32 vacancies?

21      A.    The status is summarized on HECO-R-609.

22 Q. Why was it necessary to add nightshift maintenance crews to Other Production  
23 Maintenance?

24 A. As discussed in HECO T-6 on page 9, in order to mitigate the rapid growth in  
25 demand experienced in 2004, and in anticipation of equivalent or higher demand

1           going forward, HECO had to take immediate steps to maximize the availability of  
2           its existing fleet of 16 generating units, and to figure out ways to maintain  
3           reliability of the aging fleet. Comparing the reserve margins in HECO-611 and  
4           HECO-612, in just one year, from 2003 to 2004, HECO system reserves dropped  
5           approximately 50 MW across the whole year due to the growth in demand. As  
6           experienced in 2004, actual demand outpaced the anticipated demand projections  
7           in the 2004 Adequacy of Supply letter to the Commission (HECO-606), and the  
8           impacts to the HECO system are expected to continue until permitting and  
9           installation of the planned simple-cycle combustion turbine can be expected to be  
10          completed.

11                       Maintaining reliability of an aging fleet entailed looking at labor  
12           availability as well as available daily periods where meeting Spinning Reserve  
13           and Quickload Pickup generation criteria were not an issue with regard to meeting  
14           peak demand or responding to forced outages. To this end, off-peak periods  
15           shown in HECO-624 provide an opportunity to accomplish certain types of  
16           maintenance with minimal risk to the system. For example, maintenance on  
17           baseloaded units requiring a unit derating and/or risk condition can be performed  
18           while the unit continues to operate at minimum loads. Maintenance on cycling  
19           and peaking units can be performed after they shutdown for the night and before  
20           they are scheduled to startup the following day. The Waiau night shift  
21           maintenance crew can also provide support during off-peak periods to the  
22           Honolulu Station. Please refer to HECO's response to CA-IR-48.

23          Q.   Why should the labor cost for these additional positions be annualized for the full  
24               12 months in the 2005 TY?

25          A.   The vacancies created by the increase in staffing to man the nightshift

1 maintenance crews are NOT the same as vacancies of existing positions that are  
2 created due to retirement, transfers or terminations. Using the CA's method of  
3 averaging will seriously understate Other Production Maintenance – Labor  
4 expenses. Further, night shift maintenance cannot be performed with a  
5 disproportionate number of unsupervised outside contractors for safety and  
6 environmental compliance reasons.

7 While unanticipated hiring delays have been experienced due to Union  
8 related issues, all approvals have been settled and active hiring is in progress. It is  
9 anticipated that by the end of the test year most of the positions will be filled.  
10 Vacancies created through retirements, transfers and/or terminations will also be  
11 filled and Other Production Maintenance – Labor expenses will be incurred by the  
12 time rates are in effect.

13 Q. In its response to HECO/CA-IR-116, the CA claims that "The Consumer  
14 Advocate's overall production maintenance expense allowed in the test period is  
15 conservatively generous to HECO ...". Is this a fair conclusion?

16 A. Absolutely not. HECO provided the CA with voluminous information, at the  
17 CA's request, showing that, as of April 8, 2005, actual overhaul maintenance  
18 expenses in 2005 are expected to substantially exceed, by over \$3.6 million, the  
19 2005 test year estimate for overhaul maintenance expense. Please refer to  
20 HECO's response to CA-IR-180, page 8. The CA does not even mention that in  
21 its testimony, much less take it into account in arriving at its "conservatively  
22 generous" estimate for 2005.

23 Q. Does the information supplied by HECO to the CA and the DOD demonstrate  
24 there is an increasing amount of maintenance work that must be performed, not  
25 only by the nightshift crews but by the entire staff of Other Production

1 Maintenance?

2 A. Yes. One of the best indications of the increasing amount of maintenance work is  
3 the number and cost of equipment overhauls. HECO's response to CA-IR-41  
4 provides the 2003 planned and actual maintenance outage schedule. HECO  
5 planned 22 maintenance outages, but 34 actual outages were required. The same  
6 information is provided for 2004 in HECO's response to CA-IR-42. HECO  
7 planned 21 maintenance outages, but 33 were required. The actual vs. planned  
8 outage schedules in CA-IR-41 for 2003, and in CA-IR-42 for 2004, clearly  
9 illustrate the increased maintenance trend on the generating units. Planning,  
10 scheduling, and coordinating work activities for generating unit overhauls are  
11 extremely complex. Additional Resource Planners and Planning Coordinators  
12 were forecasted to allow sufficient time to plan, schedule and coordinate  
13 overhauls. This was the only way adequate planning and preparations could be  
14 made to address complex concurrent multiple and back-to-back outages  
15 throughout the year. With regard to additional trades and craft positions for the  
16 dayshift, concurrent multiple outages creates higher volume of work and can  
17 cause multiple, conflicting needs for specific skills that are required on every  
18 generating unit undergoing an overhaul or maintenance outage at different  
19 locations, i.e., different units and/or different stations. Please refer to HECO's  
20 response to CA-IR-644.

21 Q. Has there been any trend in Other Production O&M expenses?

22 A. Yes, the age of generating units and associated infrastructure have increased  
23 actual Other Production O&M expenses over the years since 1995. HECO's  
24 response to CA-IR-37, page 3, shows the actual Other Production O&M expenses  
25 from 1995 through 2004, and 2005 Test Year. The trend shows a general and

1 significant increase due to the aging phenomena over most years from 1995  
2 through 2002 when the system had adequate capacity reserves due to lower  
3 demand than was experienced in 2003 and 2004, and is anticipated in 2005 and  
4 beyond. The combination of the factors discussed in HECO T-6 that are driving  
5 the need to increase Other Production O&M include aging units requiring more  
6 maintenance as they are operated "harder" to meet demand (HECO-601, 611,  
7 612); empirical evidence of rapidly growing demand into the foreseeable future  
8 (HECO-606, 607, 608, 609); the need to increase staffing (HECO T6, pages 22-  
9 25, and 28-31) as part of an overall mitigation plan (HECO-619, 620, 623, 624,  
10 625) to maintain availability and reliability of existing HECO generating units;  
11 and increasing regulatory impacts (HECO 610).

12 Q. In your direct testimony, you discussed the 2005 Planned Maintenance Schedule.  
13 Has HECO revised its 2005 Planned Maintenance Schedule since the time of your  
14 direct testimony?

15 A. Yes. Since the test year 2005 O&M Planned Maintenance Schedule was  
16 developed in HECO-627, a number of events in 2004, including the forced outage  
17 and overhaul on W9 which began in October 2004, triggered changes to the 2005  
18 Planned Maintenance Schedule. See CA-IR-43. The 2005 O&M Planned  
19 Maintenance Schedule was revised as of February 3, 2005. An increase in O&M  
20 project expense based on the revised 2/03/05 Planned Maintenance schedule was  
21 primarily due to the increase in work scope on W10 based on the inspection and  
22 findings on W9. The 2005 O&M Planned Maintenance Schedule was updated  
23 again on 4/8/05, to reflect changes due to the actual return date of W9, the  
24 anticipated return dates of W3, W6, and W7, and projected changes for the  
25 balance of the year. CA-IR-43 (REVISED 4/21/05), page 6, shows the revisions

1 to the O&M Overhaul Project expenses.

- 2 • 1/12/04 Schedule for the 2005 Test Year: \$14,552,702.  
3 • 2/03/05 Schedule 2005 Projected: \$17,137,600  
4 • 4/8/05 Schedule 2005 Projected: \$18,186,700

5 Please refer to HECO's response to CA-IR-180.

6 Q. Why didn't HECO propose to adjust its test year estimate for maintenance  
7 expense upwards to reflect this expected level of outage maintenance expense in  
8 2005?

9 A. As indicated in its response to CA-IR-641, HECO does not plan to change its  
10 prefiled position regarding Other Production O&M expenses except for the items  
11 noted in the "Listing and Description of Updates" provided to the parties and the  
12 Commission on May 5, 2005.

13 Q. Should overhaul maintenance expense be adjusted upwards to reflect the higher  
14 level of expected cost if Other Production O&M expenses are reduced, as the CA  
15 proposes?

16 A. Yes, because it would be unfair reduce 2005 test year expenses based on the CA's  
17 proposals, but not increase expenses based on expense data presented by HECO.

18 Q. What is HECO's position regarding the CA's proposal to reduce Other Production  
19 Maintenance – Labor in the amount of \$9,000 for the Maintenance portion of  
20 hiring lag (Exhibit CA-101, Schedule C21, page 1, column (E), line 2)?

21 A. As indicated earlier in my rebuttal testimony, this proposed adjustment is  
22 unreasonable in light of the information presented by HECO that actual expenses  
23 will almost certainly exceed 2005 test year estimates.

24 Q. What is the CA's position with regard to Other Production Maintenance –  
25 Nonlabor expenses?

1 A. Referring to Exhibit CA-101, Schedule C-9, page 1, lines 4-12, the CA proposes  
2 an overall reduction of \$690,000 for "Lowest Priority discretionary Maintenance  
3 of Structures Items."

4 Q. What is HECO's position with regard to the CA's proposed reductions of  
5 \$690,000 to Other Production Maintenance – Nonlabor expenses?

6 A. HECO disagrees with the CA's proposed reductions. The CA's perspective on  
7 this issue is narrow and does not take into account that the identified items on the  
8 list provided in CA-IR-244 are real maintenance items that need to get done.  
9 While it is true that HECO has discretion regarding scheduling Production  
10 Maintenance, it does not follow that \$690,000 can be cut from the Production  
11 Maintenance budget without diminishing HECO's ability to perform essential  
12 maintenance. As noted earlier in my testimony, unplanned maintenance outages  
13 are on the rise and the whole maintenance management process is becoming ever  
14 more complex. Even though Production Maintenance in theory has the discretion  
15 to decide to forego certain lower priority projects, in practice, it would be  
16 unreasonable to simply remove \$690,000 from the budget on the hope that the  
17 ~~money would not be needed for unplanned high priority maintenance work~~

[REDACTED]

[REDACTED]

[REDACTED]

and schedule, will increase as units are operated much harder than in the past. For example the increases in overhaul costs attributed to increased and unanticipated scope of work since the development of the test year estimate based on the 1/12/04 schedule more than offsets the amount of "Lowest Priority discretionary Maintenance of Structures" proposed by the CA. Reducing base rates by the CA's

proposed amount will negatively impact the flexibility required to redirect those Nonlabor resources to pay for higher overhaul costs due to unanticipated scope increased caused by the age and wear of the generating units.

**Q. Please summarize the items that have not reached agreement between HECO and the CA on Other Production Operations and Maintenance – Labor and Nonlabor expenses.**

**A. HECO-R-610 compares HECO's rebuttal position with the CA's proposed**

1 estimate for Production O&M of \$56,497,000?

2 A. The DOD's proposed Production O&M of \$51,439,000 is \$5,058,000 less than  
3 HECO's rebuttal Production O&M of \$56,497,000.

4 Q. In what areas are HECO and the DOD in agreement?

5 A. HECO and the DOD agree to decrease Other Production O&M – Nonlabor  
6 expense by \$470,000; \$313,000 from Other Production Operation – Nonlabor, and  
7 \$157,000 from Other Production Maintenance – Nonlabor. (See HECO-R-612)

8 Q. Please describe the adjustments to Other Production Operation – Nonlabor.

9 A. The \$313,000 reduction to Other Production Operation – Nonlabor expenses is  
10 comprised of reductions due to removal of CHP Operations expense of \$62,000  
11 (see HECO TR-7, pages 1-3), reduction of Kahe water expense of \$101,000,  
12 removal of Sunpower for Schools expense of \$75,000, and removal of Purchase  
13 Power Tolling Study expense of \$75,000.

14 Q. Please describe the adjustment to Other Production Maintenance – Nonlabor  
15 expense.

16 A. The \$157,000 reduction to Other Production Maintenance – Nonlabor expense is  
17 due to the removal of CHP Maintenance expense. (See HECO TR-7, pages 1-3.)

18 Q. Did the DOD propose other adjustments to Other Production O&M?

19 A. Yes, as shown in HECO-R-613, the DOD proposes reductions in Other  
20 Production Operations Labor and Nonlabor expenses totaling \$1,908,000, and a  
21 reduction in Other Production Maintenance Labor of \$1,224,000.

22 Q. Is HECO in agreement with the DOD's proposed reduction of \$1,908,000 for  
23 Other Production Operation Labor and Nonlabor?

24 A. No. As shown in HECO-R-613, the DOD proposes to reduce Operations Labor  
25 by \$339,000 and Operations Nonlabor by \$1,569,000.

1 Q. What is HECO's position on the DOD's proposed reduction of \$339,000 in Other  
2 Production Operations – Labor expense?

3 A. HECO's position is that Other Production Operations – Labor should not be  
4 reduced by \$339,000. The DOD derived the proposed reduction using an  
5 "averaging" methodology similar to the one used by the CA, and it is subject to  
6 the same flaws and practical difficulties as the CA's proposed method that I  
7 described in detail earlier in the rebuttal testimony.

8 Q. What is HECO's position on the DOD's proposed reduction of \$1,569,000 in  
9 Other Production Operations – Nonlabor expense?

10 A. HECO's position is that Other Production Operations – Nonlabor SHOULD NOT  
11 be reduced by \$1,569,000. The DOD's proposed Nonlabor reductions are  
12 comprised of a proposed reduction for CHP fuel expense of \$838,000, and a  
13 proposed reduction for Kahe 7 Amortization expenses of \$731,000.

14 Q. Please expand on HECO's position with regard to a reduction of \$838,000 for  
15 CHP fuel expense.

16 A. The \$838,000 proposed reduction for CHP fuel expense is an error and should not  
17 be included in the DOD's proposed adjustments to Other Production Operation –  
18 Nonlabor expenses. This matter is discussed Scott Seu's rebuttal testimony, RT-7.

19 Q. Please expand on HECO's position with regard to a reduction of \$731,000 for  
20 Kahe 7 Amortization expense.

21 A. HECO's position on the DOD's proposed reduction of \$731,000 for the Kahe 7  
22 Amortization expense is explained in HECO RT-13, pages 19-22.

23 Q. Are there any adjustments proposed by HECO where the DOD has not taken a  
24 position?

25 A. Yes. The DOD did not take a position for the addition of Distributed Generation

1 (DG) which impacts Other Production O&M. HECO's rebuttal position as  
2 discussed in HECO RT-7, pages 6-11, supports adding an annualized O&M  
3 amount of \$1,466,000 to Other Production O&M to allow for the operation and  
4 maintenance of nine (9) DG units that will be operational by October, 2005. The  
5 DOD also did not take a position regarding HECO's proposed addition to Other  
6 Production O&M expenses for the \$490,000 betterment accounting adjustment.  
7 HECO/DOD-IR-101.

8 Q. What comprises the DOD's proposed reduction in Other Production Maintenance  
9 Labor of \$1,224,000?

10 A. The DOD used its averaging methodology and applied an adjustment factor of  
11 50% to derive the DOD's proposed reduction in Other Production Maintenance  
12 Labor expense of \$1,224,000.

13 Q. What is HECO's position on the DOD's proposed reduction of \$1,224,000 in  
14 Other Production Maintenance – Labor expense?

15 A. HECO's position is that Other Production Maintenance – Labor should not be  
16 reduced by \$1,224,000. I have discussed in detail earlier in the rebuttal testimony  
17 why the "averaging" methodology is unreasonable.

18 Q. Please explain the status of vacancies created through retirements, transfers and

2 Q. Briefly describe the eight additional positions

3 A. The BEP program was created to bring engineers with less experience into the  
4 power plant support groups and provide the training and experience required of fully  
5 qualified engineers. The first part of the program expects:

- 6 • Beginning Engineer will become familiar with power plant systems,  
7 components, operations and maintenance.
- 8 • Beginning Engineer will be exposed to major outage activities and have  
9 opportunities to observe equipment undergoing an overhaul.
- 10 • Beginning Engineer will receive formal training and also on-the-job training.
- 11 • Beginning Engineer will establish relationships that will enhance cooperation  
12 and interaction with the power plant personnel.
- 13 • Beginning Engineer will gain an understanding of the challenges that the Power  
14 Supply O&M staff face to keep units maintained and operating smoothly.

15 There are four Engineer positions designated for the BEP program. All four positions  
16 were filled in December 2004 (3 positions) and March 2005 (1 position). Charges made

1 primarily go to HELCO billable work (80%) and clearing (20%).

2 Finally, one Project Manager position was added to PSED. This position was  
3 added to provide project management support for the various Power Supply projects.  
4 This position was filled in December 2004. Charges made by this position will  
5 primarily go to capital (80%) and clearing (20%).

6 Q. In addition to what you've just described, does HECO plan to add any other  
7 unforecasted engineer positions?

8 A. Yes. Power Supply Operations and Maintenance is planning to add two  
9 unforecasted operations engineers.

10 Please summarize HECO's rebuttal position relative to the CA and DOD?

11 A. HECO-R-614 summarizes HECO's rebuttal position relative to the CA and DOD.

12 Q. Does this conclude your testimony?

13 A. Yes it does.

14

15

16

17

18

19

20

21

22

23

24

25

Hawaiian Electric Company, Inc.  
2005 TEST YEAR

OTHER PRODUCTION OPERATION & MAINTENANCE EXPENSES  
(\$ Thousands)

<u>Line</u>	(A)	(B)	(C)
	HECO Direct	Adjust- ments	HECO Rebuttal
1 Production Operations	23,877	(239)	23,638
2 Production Maintenance	31,164	1,695	32,859
3 TOTAL PRODUCTION O&M	55,041	1,456	56,497

Source: Column A: HECO-614  
Column B, Line 1: HECO-R-603  
Column B, Line 2: HECO-R-604  
Column C: Column A + Column B

Hawaiian Electric Company, Inc.  
2005 TEST YEAR

OTHER PRODUCTION OPERATION & MAINTENANCE EXPENSES  
(\$ Thousands)

	(A)	(B)	(C)
<u>Line</u>	<u>HECO Direct</u>	<u>Adjust- ments</u>	<u>HECO Rebuttal</u>
PRODUCTION OPERATION			
1 Labor	13,398	0	13,398
2 Non-Labor	<u>10,479</u>	<u>(239)</u>	<u>10,240</u>
3 Total Operation	23,877	(239)	23,638
PRODUCTION MAINTENANCE			
4 Labor	12,372	0	12,372
5 Non-Labor	<u>18,792</u>	<u>1,695</u>	<u>20,487</u>
6 Total Maintenance	31,164	1,695	32,859
7 TOTAL PRODUCTION O&M	<u>55,041</u>	<u>1,456</u>	<u>56,497</u>

Source: Column A: HECO-615  
Column B, Line 1: HECO-R-603, Line 1  
Column B, Line 2: HECO-R-603, Line 2 - 8  
Column B, Lines 4: HECO-R-604, Line 1  
Column B, Lines 5: HECO-R-604, Lines 2 - 6  
Column C: Column A + Column B

Hawaiian Electric Company, Inc.  
2005 TEST YEAR

PRODUCTION OPERATION EXPENSES  
(\$ Thousands)

<u>Line</u>	(A)		(B)
	Adjust- ments		Description
1 Labor	0		
2 Non-Labor	(62)		Remove of Combined Heat & Power expense
3	98		Add Distributed Generation expense
4	(75)		Remove of Sun Power for Schools expense
5	(101)		Reduce Kahe water consumption expense
6	(75)		Remove Purch Pwr Tolling Arrangement Study exp
7	(20)		Reduce EPRI R&D expense
8	<u>(4)</u>		Reduce Ellipse expense
9 TOTAL OPERATIONS ADJUSTMENTS	<u>(239)</u>		

Hawaiian Electric Company, Inc.  
2005 TEST YEAR

PRODUCTION MAINTENANCE EXPENSES  
(\$ Thousands)

<u>Line</u>		
	(A)	(B)
	Adjust- ments	Description
1 Labor	0	
2 Non-Labor	(157)	Remove of Combined Heat & Power expense
3	490	Add Betterment Accounting adjustment
4	1,305	Add Substation Distributed Generation expense
5	63	Increase Substation Distributed Generation expense
6	(6)	Reduce Ellipse expense
7 TOTAL MAINTENANCE ADJUSTMENTS	<u>1,695</u>	

Source: Column A, Lines 2 - 4: May 5th update letter; CA-IR-641  
Column A, Line 5 - 6: HECO-RT-6

Hawaiian Electric Company, Inc.  
Materials & Supplies Inventory  
(\$ in thousands)

	(A)	(B)	(C)	(D)	(E)
	<u>Direct Testimony</u>	<u>12/31/04</u>	<u>12/31/05</u>	<u>Rebuttal</u>	<u>Variance</u>
1 Production	5,329	5,489	5,294	5,392	63
2 T&D	<u>5,192</u>	<u>5,554</u>	<u>5,031</u>	<u>5,293</u>	<u>101</u>
3 Total Materials & Supplies	10,521	11,043	10,325	10,684	163
4 Adjustment to Materials & Supplies	<u>(536)</u>	<u>(618)</u>	<u>(536)</u>	<u>(577)</u>	<u>(41)</u>
5 Adjusted Total for Materials & Supplies	<u><u>9,984</u></u>	<u><u>10,425</u></u>	<u><u>9,789</u></u>	<u><u>10,107</u></u>	<u><u>123</u></u>

Source:

Column A and C, Lines 1 - 5: HECO-1903.  
Column B, Lines 1-5: CA-IR-95, page 3 of 4.  
Column D = (B + C)/2  
Column E = D - A

Note:

Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.  
Materials & Supplies Inventory - Production  
(\$ in thousands)

	(A)	(B)	(C)	(D)	(E)
	<u>Direct Testimony</u>	<u>12/31/2004</u>	<u>12/31/2005</u>	<u>Rebuttal</u>	<u>Variance</u>
1 Production	5,329	5,489	5,294	5,392	63
2 Adjustment	<u>(192)</u>	<u>(239)</u>	<u>(192)</u>	<u>(216)</u>	<u>(24)</u>
3 Adjusted Total	<u>5,137</u>	<u>5,250</u>	<u>5,102</u>	<u>5,176</u>	<u>39</u>

Source:

Column A and C, Line 1: HECO-1903.

Column B, Line 1: CA-IR-95, page 3.

Column D = (B + C)/2

Column E = D - A

Note:

Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.  
Materials & Supplies Inventory - T&D  
(\$ in thousands)

	(A)	(B)	(C)	(D)	(E)
	<u>Direct Testimony</u>	<u>12/31/2004</u>	<u>12/31/2005</u>	<u>Rebuttal</u>	<u>Variance</u>
1 T&D	5,192	5,554	5,031	5,293	101
2 Adjustment	<u>(343)</u>	<u>(379)</u>	<u>(343)</u>	<u>(361)</u>	<u>(18)</u>
Adjusted					
3 Total	<u>4,849</u>	<u>5,175</u>	<u>4,688</u>	<u>4,932</u>	<u>83</u>

Source:

Column A and C, Line 1: HECO-1903.

Column B, Line 1: CA-IR-95, page 3.

Column D = (B + C)/2

Column E = D - A

Note:

Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.  
2005 TEST YEAR

COMPARISON OF HECO AND CONSUMER ADVOCATE PROPOSED

OTHER PRODUCTION OPERATION & MAINTENANCE EXPENSES  
(\$ Thousands)

<u>Line</u>	(A)	(B)	(C)
	HECO Direct	CA Adjustment	CA Direct
1 Production Operations	23,877	(1,784)	22,093
2 Production Maintenance	31,164	(1,388)	29,776
3 TOTAL PRODUCTION O&M	55,041	(3,172)	51,869

Source: Column A: HECO-614  
Column B, Line 1: HECO-R-607  
Column B, Line 2: HECO-R-608  
Column C: Column A + Column B

Note: Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.  
2005 TEST YEAR

CA PROPOSED ADJUSTMENTS TO  
PRODUCTION OPERATION EXPENSES  
(\$ Thousands)

<u>Line</u>		(A)	(B)
		Adjust- ments	Description
	Labor		
1		(218)	Average Staffing
2		(50)	Standard Labor Rate & OT
3		(10)	Hiring Lag
	Non-Labor		
4		(62)	Remove of Capital Budgeting Expenses
5		(101)	Reduce Kahe water consumption expense
6		(75)	Remove of Sun Power for Schools expense

Hawaiian Electric Company, Inc.  
2005 TEST YEAR

CA PROPOSED ADJUSTMENTS TO  
PRODUCTION MAINTENANCE EXPENSES  
(\$ Thousands)

<u>Line</u>	(A)	(B)
	<u>Adjust- ments</u>	<u>Description</u>
Labor		
1	(1,194)	Normalize for Average Staffing
2	(46)	Standard Labor Rate & OT
3	(9)	Hiring Lag
Non-Labor		
4	(157)	Remove of Combined Heat & Power expense
5	490	Add Betterment Adjustment
6	252	Add Distributed Generation
7	(690)	Eliminate Lowest Priority Non-Labor expense
8	<u>(34)</u>	Remove Ellipse Software
9	<u>(1,388)</u>	
TOTAL MAINTENANCE ADJUSTMENTS		

Source: Column A, Line 1: CA-101, Schedule C-9, line 1  
Column A, Lines 2: Maintenance portion of CA-101, Schedule C, page 4, column E, line 5  
Column A, Lines 3: Maintenance portion of CA-101, Schedule C-21, page 1, column E, line 2  
Column A, Line 4: CA-101, Schedule C-6, line 12  
Column A, Line 5: CA-101, Schedule C-9, line 13  
Column A, Line 6: CA-101, Schedule C-7, line 6  
Column A, Line 7: CA-101, Schedule C-9, line 12  
Column A, Line 8: CA-101, Schedule C-14, footnote (d), Production O&M Nonlabor X 0.5  
Column A, Line 9: Sum Lines 1 to 8

Hawaiian Electric Company, Inc.  
Production O&M  
Staffing - Update with Actuals as of 06/30/05

Position	RA	TY 2005	Actuals 06/30/05	Comments
Power Supply Service Manager	IA	1	1	
Power Supply Service Secretary	IA	1	1	
Administrator	IA	1	1	
Contracts Administrator	IA	1	2	2nd position converted from Admin Assistant
Administrative Assistant	IA	1	0	Converted to Contracts Administrator.
Power Supply O&M Manager	IB	1	1	
Power Supply O&M Secretary	IB	1	1	
Budget Analyst	IB	1	1	
Technical Trainer	IB	2	2	
Principal Staff Engineer	IB	1	0	
Envir Compliance Supervisor	IB	1	1	
Station Chemist	IB	2	2	
IT Specialist	IB	1	0	
Lead Func Admin Work Mgmt	IB	0	0	
Purchase Power Director	IC	1	1	
PPC Administrator	IC	3	3	
Administrative Assistant	IC	2	2	
Agency Temp	IC	0	0	
Fuel Resource Director	IF	1	1	
Fuels Contract Administrator	IF	1	1	Title Change from Fuels Procurement Specialist
Admin / Engineer II	IF	1	0	Position transferred to Power Supply Engineering Dept.
Forecast Planning Analyst	IF	0	1	Position transferred from Power Supply Engineering
Fuels Records Clerk	IF	1	1	
Admin Fuels Operations	IF	1	0	
Honolulu Senior Supervisor	IH	1	1	
Honolulu Clerk	IH	1	0	Considering reassignment to support Technical Trainer.
Shift Supervisor	IH	5	4	Shift Supervisor position to be filled 11/07/05.
Honolulu Operators	IH	19	19	24X7 schedule started on 6/27/05
Kahe Senior Shift Supervisor	IK	1	0	Selection in progress.
Kahe Station Aide	IK	1	1	
Shift Supervisor	IK	7	7	
Kahe Operators	IK	49	46	Filled 07/11/05 or targeted to fill 09/19/05.
Kahe Maint Supervisor	IL	3	2	+1 Night Shift - To be transfered to IT. To be posted 08/05.
Boiler Working Foreman	IL	2	1	+1 Night Shift - To be transfered to IT. To be posted 08/05.
Elec Working Foreman	IL	2	1	+1 Night Shift - To be transfered to IT. To be posted 08/05.
Machinist Working Foreman	IL	2	1	+1 Night Shift - To be transfered to IT. To be posted 08/05.
* Senior Electrician	IL	5	4	+1 Night Shift - To be transfered to IT. To be posted 08/05.
* Machinist	IL	4	3	+1 Night Shift - To be transfered to IT. To be posted 08/05.
* Pipefitter Mechanic	IL	5	3	to transfer from IT 07/05.
* Certified Comb Welder	IL	4	3	+1 Night Shift - To be transfered to IT. To be posted 08/05.
* Control Technician	IL	8	6	+2 Night Shift - To be transfered to IT. To be posted 08/05.
* Helper	IL	2	2	
Mobile Crn & Hvy Eq Operator	IL	1	2	
O&M Maint Superintendent	IM	1	1	
Maintenance Clerk	IM	1	1	

Hawaiian Electric Company, Inc.

Production O&M

Staffing - Update with Actuals as of 06/30/05

Position	RA	TY 2005	Actuals 06/30/05	Comments
Honolulu Maint Supervisor	IN	1	1	
Boiler Working Foreman	IN	1	1	
Elec Working Foreman	IN	1	1	
Machinist Working Foreman	IN	1	1	
* Senior Electrician	IN	1	1	
* Machinist	IN	1	1	
* Cert Equip/Pipefitter Mechanic	IN	1	1	
* Control Technician	IN	2	2	
Operating Superintendent	IO	1	1	
Senior Supervisor	IO	0	0	
Operations Power Engineer	IO	0	2	
Planning Superintendent	IP	1	1	
Power Plant Clerk	IP	1	1	
Senior Supervisor	IP	1	1	
Resource Planner	IP	8	8	
Planning/Project Coordinator	IP	2	0	1 position offer accepted and will be filled 08/01/05; 2nd position reposted internally & externally 07/24/05.
O&M Engineer	IP	3	1	Selection in progress.
PDM Supervisor	IP	1	1	
PDM Specialist	IP	3	3	
BRO Engineer	IP	1	1	
Traveling Maint Supervisor	IT	4	4	
Boiler Working Foreman	IT	2	2	
Elec Working Foreman	IT	2	2	
Machinist Working Foreman	IT	2	2	
Insulator Working Foreman	IT	1	1	
Condenser Crew Leader	IT	1	1	
* Senior Electrician	IT	8	8	Plan is to have 9 total Sr Electricians instead of 8; Selection in progress.
* Machinist	IT	9	7	Selection in progress.
* Pipefitter Mechanic	IT	7	6	
* Certified Equip Mechanic	IT	1	1	
* Certified Comb Welder	IT	7	5	Selection in progress.
* Control Technician	IT	7	6	Selection in progress.
* Helper	IT	4	3	Will use Helper Position to add 1 add'l Sr Electrician (listed above). Plan is to have 3 total Helpers instead of 4.
* Insulator	IT	11	10	Selection in progress.
* Condenser Cleaner	IT	8	5	Selection in progress.
Waiau Senior Shift Supervisor	IW	1	1	
Waiau Station Aide	IW	1	1	
Shift Supervisor	IW	7	7	
Waiau Operators	IW	53	49	24X7 schedule started on 03/21/05. To be filled 07/11/05 or targeted to fill 09/19/05.

Hawaiian Electric Company, Inc.

Production O&M

Staffing - Update with Actuals as of 06/30/05

	Position	RA	TY 2005	Actuals 06/30/05	Comments
	Waiau Maint Supervisor	IX	3	2	+1 Night Shift - To be transfered to IT. To be posted 08/05.
	Boiler Working Foreman	IX	2	1	+1 Night Shift - To be transfered to IT. To be posted 08/05.
	Elec Working Foreman	IX	2	1	+1 Night Shift - To be transfered to IT. To be posted 08/05.
	Machinist Working Foreman	IX	2	1	+1 Night Shift - To be transfered to IT. To be posted 08/05.
*	Senior Electrician	IX	5	3	+1 Night Shift - To be transfered to IT. To be posted 08/05.
*	Machinist	IX	4	3	+1 Night Shift - To be transfered to IT. To be posted 08/05.
*	Pipefitter Mechanic	IX	5	4	+1 Night Shift - To be transfered to IT. To be posted 08/05.
*	Certified Comb Welder	IX	4	3	+1 Night Shift - To be transfered to IT. To be posted 08/05.
*	Control Technician	IX	8	6	+2 Night Shift - To be transfered to IT. To be posted 08/05.
*	Helper	IX	1	1	
	Mobile Crn & Hvy Eq Operator	IX	1	1	

Total            354      307

\* Indicates a position which could be filled by outside contractors.

Hawaiian Electric Company, Inc.  
2005 TEST YEAR

COMPARISON OF HECO REBUTTAL POSITION  
AND CONSUMER ADVOCATE ADJUSTMENTS FOR  
OTHER PRODUCTION OPERATION & MAINTENANCE EXPENSES  
(\$ Thousands)

<u>Line</u>	(A)	(B)
	<u>HECO Rebuttal</u>	<u>CA Adjustment</u>
1 CHP Adjustment	(220)	(220)
2 Kahe City Water	(101)	(101)
3 SunPower For Schools Adjustment	(75)	(75)
4 Purchase Power Tolling Study	(75)	(75)
5 Betterment Adjustment	490	490
6 Distributed Generation	1,466	394
7 Normalize for Average Staffing		(1,412)
8 Emissions Fee		(69)
9 Electronic Shock Absorber & R&D	(20)	(500)
10 Kahe 7 Amortization		(731)
11 Lowest Priority Maintenance Non labor		(690)
12 Ellipse Cost	(10)	(68)
13 Standard Labor Rate & OT		(96)
14 Hiring Lag		(19)
Total	<u>1,456</u>	<u>(3,172)</u>

Source:

Column A: HECO-R-603 and HECO-R-604

Column B: HECO-R-607 and HECO-R-608

Hawaiian Electric Company, Inc.  
2005 TEST YEAR

COMPARISON OF HECO AND DEPARTMENT OF DEFENSE PROPOSED  
OTHER PRODUCTION OPERATION & MAINTENANCE EXPENSES  
(\$ Thousands)

<u>Line</u>	(A)	(B)	(C)
	HECO Direct	DOD Adjustment	DOD Direct
1 Production Operations	23,877	(2,221)	21,656
2 Production Maintenance	31,164	(1,381)	29,783
3 TOTAL PRODUCTION O&M	55,041	(3,602)	51,439

Source: Column A: HECO-614  
Column B: DOD-118 and DOD-120  
Column C: Column A + Column B

Note: Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.  
2005 TEST YEAR

AREAS OF AGREEMENT IN REBUTTAL POSITIONS  
OTHER PRODUCTION OPERATION & MAINTENANCE EXPENSES  
(\$ Thousands)

<u>Line</u>		(A)	(B)
		<u>HECO Rebuttal</u>	<u>DOD Adjustment</u>
	Operations Non-Labor		
1	CHP Adjustment	(62)	(62)
2	Kahe City Water	(101)	(101)
3	SunPower For Schools Adjustment	(75)	(75)
4	Purchase Power Tolling Study	<u>(75)</u>	<u>(75)</u>
5	Subtotal	(313)	(313)
	Maintenance Non-Labor		
6	CHP Adjustment	<u>(157)</u>	<u>(157)</u>
7	Subtotal	(157)	(157)
8	TOTAL NON-LABOR ADJUSTMENT	<u><u>(470)</u></u>	<u><u>(470)</u></u>

Hawaiian Electric Company, Inc.  
2005 TEST YEAR

OTHER PRODUCTION OPERATION & MAINTENANCE EXPENSES  
OTHER DOD PROPOSED ADJUSTMENTS  
(\$ Thousands)

		(A)	(B)
<u>Line</u>		<u>DOD Adjustment</u>	
	<u>Operations Labor</u>		
1	Average TY Employee	<u>(339)</u>	
	<u>Operations Non-Labor</u>		
2	CHP Fuel	(838)	
3	Kahe 7 Amortization	(731)	
4	Total Operations Non-Labor	<u>(1,569)</u>	
5	TOTAL OPERATIONS		(1,908)
	<u>Maintenance Labor</u>		
6	Average TY Employee	<u>(1,224)</u>	
7	TOTAL MAINTENANCE		(1,224)
8	TOTAL OTHER PROPOSED ADJUSTMENT		<u>(3,132)</u>

Source:

Column A, Line 1: DOD-118, (Lines 9 - 13) X 0.50  
Column A, Line 2: DOD-120, Line 2  
Column A, Line 3: DOD-120, Line 7  
Column A, Line 4: Column A, Line 2 + Column A, Line 3  
Column B, Line 5: Column A, Line 1 + Column A, Line 4  
Column A, Line 6: DOD-118, (Lines 14 - 18) X 0.50  
Column B, Line 7: Column A, Line 6  
Column B, Line 8: Column B, Line 5 + Column B, Line 7

Hawaiian Electric Company, Inc.  
2005 TEST YEAR

OTHER PRODUCTION OPERATION & MAINTENANCE EXPENSES  
(\$ Thousands)

COMPARISON OF POSITION

<u>Line</u>	(A)	(B)	(C)
	HECO Rebuttal	CA Direct	DOD Direct
1 Production Operations	23,638	22,093	21,656
2 Production Maintenance	32,859	29,776	29,783
3 TOTAL PRODUCTION O&M	56,497	51,869	51,439

Source: Column A: HECO-R-614  
Column B: HECO-R-606  
Column C: HECO-R-611

TESTIMONY OF  
SCOTT W. H. SEU, P. E.

MANAGER  
ENERGY PROJECTS DEPARTMENT  
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Removal of Combined Heat and Power Project Expenses  
Installation and Operation of Distributed Generation Units at  
HECO Sites and Associated Expenses  
Energy Projects Department Expense

INTRODUCTION

1

2 Q. Please state your name and business address.

3 A. My name is Scott W. H. Seu. My business address is P.O. Box 2750, Honolulu,  
4 Hawaii 96840. I am the manager of HECO's Energy Projects Department.

5 Q. Mr. Seu, have you previously submitted testimony in this proceeding?

6 A. Yes. I submitted written direct testimony, exhibits, and supporting workpapers as  
7 HECO T-7.

8 Q. What is the scope of your rebuttal testimony?

9 A. My rebuttal testimony will:

- 10 1) Discuss the removal of combined heat and power ("CHP") project expenses  
11 from the 2005 test year rate case;
- 12 2) Explain the addition to the 2005 test year rate case of the capital costs and  
13 expenses associated with the installation, operation, and maintenance of  
14 nine distributed generation ("DG") units at HECO sites and HECO's basis  
15 for including these costs in the test year revenue requirements and  
16 annualizing operating expenses;
- 17 3) Describe the current status of HECO's efforts to install DG units at HECO  
18 sites as a reserve capacity shortfall mitigation measure;
- 19 4) Describe the updated Energy Projects Department test year expenses; and  
20 5) Discuss issues on which the Consumer Advocate and the Department of  
21 Defense agree and issues on which they disagree with HECO's positions.

22 Q. Have the removal of CHP expenses and the addition of DG capital costs and  
23 expenses been raised previously in this proceeding?

24 A. Yes. They were described in Attachment 1A of HECO's rate case updates filed  
25 with the Consumer Advocate, the Department of Defense, and the Commission on

1 May 5, 2005. They were also discussed in HECO's response to DOD/HECO-IR-  
2 9-10. My rebuttal testimony updates and expands on that information.

3

4

REMOVAL OF CHP PROJECT EXPENSES

5 Q. What CHP expenses are being removed?

6

A. As stated in HECO's response to DOD/HECO-IR 9-10, HECO has removed the following

7 following CHP expenses from the test year:

8 1) CHP System Capital Expense \$9,547,000

9 2) CHP System O&M Expense \$219,851

10 3) CHP System Diesel Fuel Expense \$983,716

1 in the Distributed Generation Proceeding (Docket No. 03-0371). Following the  
2 issuance of these orders, Pacific Allied Products, by letter dated February 9, 2005,  
3 terminated its CHP Agreement with HECO for the Pacific Allied CHP Project. A  
4 formal notice withdrawing the Pacific Allied-HECO CHP Agreement from review  
5 was filed with the Commission on March 4, 2005.

6 In view of these developments, HECO does not anticipate the completion of  
7 any utility CHP projects during the 2005 test year. As a result, CHP project  
8 revenues, expenses, and capital costs are removed from the test year.

9 Q. What are the positions of the Consumer Advocate and the Department of Defense  
10 concerning this issue?

11 A. The Consumer Advocate concurs with the removal of CHP project revenues,  
12 expenses, and capital costs from the test year. The CA confirmed in its response  
13 to HECO/CA-IR-120 that its rate base adjustment in CA Exhibit 101, Schedule E,  
14 page 1, line 7 for the elimination of the Combined Heat & Power Projects is not  
15 necessary because that schedule at line 5 already reflected the deletion of the CHP  
16 projects in the Update of Net Plant Additions.

17 The DOD agrees that the \$838,000 fuel expense for utility-owned CHP  
18 should not be removed from Production O&M expenses. See the DOD's  
19 responses to HECO/DOD-IR-113 and HECO/DOD-IR-114. The DOD has not  
20 taken a position regarding the removal of the remaining CHP expenses set forth  
21 above in my rebuttal testimony.

22  
23 2005 TEST YEAR DG PROJECTS

24 Q. Please summarize the background to HECO's 2005 DG mitigation effort, as  
25 explained in Attachment 1A of HECO's rate case updates filed with the Consumer

1 Advocate, Department of Defense, and the Commission on May 5, 2005.

2 A. HECO is adding to its test year revenue requirement the capital costs and  
3 expenses associated with the installation, operation, and maintenance of three  
4 leased 1.64 MW diesel generating units each at three HECO sites, for a total of  
5 nine DG units and 14.76 MW. As described in the 2005 HECO Adequacy of  
6 Supply ("AOS") letter filed with the Commission on March 10, 2005, given the  
7 expected reserve capacity shortfalls HECO may experience over the next several  
8 years, HECO is working to plan and implement a number of interim mitigation  
9 measures including the use of portable, leased DG units at HECO-controlled  
10 substation sites and other sites.

11 Q. What is the purpose of this effort?

12 A. The primary objective of this effort is to install dispatchable, firm generating  
13 capacity for peaking purposes as quickly as possible to mitigate the potential  
14 reserve capacity shortfalls. HECO determined that small scale DG located at  
15 HECO sites other than power plants would be the most feasible way in which to  
16 accomplish this objective. Such installations, if appropriately sited and limited in  
17 size and operation, can be permitted and installed relatively quickly compared to  
18 central station generating units.

19 Q. How did HECO decide on the use of diesel engine generators?

20 A. HECO began considering this DG mitigation measure in late October, 2004.  
21 Initial contacts with DG equipment vendors focused HECO's review on the use of  
22 mobile diesel engine generating units which are commonly deployed by industry  
23 in Hawaii and on the mainland where there is a need for quickly available power.

24 Q. What is the current status of these projects?

25 A. HECO is on track with installing the nine DG units in the September-October

2005 timeframe. The Company has completed its final site selection and will be installing the DG at Ewa Nui Substation, Helemano Substation, and the Iwilei Tank Farm. The first three units will be placed in service at Ewa Nui Substation by the end of September, the second three units at Iwilei Tank Farm by mid-October, and the last three units at Helemano Substation by the end of October.

6 Q. Have the necessary permits and approvals been secured for the projects?

7 A. Yes. The most critical permits for the projects are the noncovered source air  
8 permits from the State Department of Health (“DOH”). Noncovered source air  
9 permits were issued for the three sites on July 13, 2005.

10 Also of critical importance was understanding what land use permits were

11 continued from page 10 17 1 1 0005 1 0% 0 0 1 000 1 1

2005 TEST YEAR DG EXPENSES

Q. Where are DG expenses included in the 2005 test year estimate?

A. Non-fuel DG expenses are included in Other Production Operations - Non-labor Expense, which are described by Mr. Fujinaka in HECO RT-6, HECO-R-603 and HECO-R-604. DG fuel expenses are included in the HECO Fuel Expenses which are described by Mr. Sakuda in HECO RT-4 and HECO-404, page 2. The expense figures provided in RT-6 and RT-4 update the expenses described in Attachment 1A of HECO's rate case updates filed with the Consumer Advocate, the Department of Defense, and the Commission on May 5, 2005. A summary of the overall DG expenses for the 2005 DG installations is provided on page 1 of HECO-R-701.

Q. Were DG expenses included in HECO's written direct testimony?

A. No, because although HECO began considering the DG mitigation measure in late October, 2004, it did not decide to implement the DG projects until early 2005.

Q. What positions have the Consumer Advocate and Department of Defense taken regarding inclusion of the DG costs in the test year rate base and operating expenses?

A. With regard to capital costs, the Consumer Advocate and Department of Defense support the inclusion of the DG costs in rate base on an average test year basis. With regard to DG operations and maintenance ("O&M") expense, the Consumer Advocate does not concur with HECO's proposal to normalize the impact on O&M expenses by including the annual O&M expenses for the nine units in expenses for the 2005 test year, and instead proposes to include only the amount of expenses incurred from the initial start date of the units through the end of the test year. I will address the Consumer Advocate's position later in my testimony,

1 after describing the costs of the DG projects. The Department of Defense has not  
2 taken a position on the DG O&M expenses in its direct testimony (See the DOD's  
3 response to HECO/DOD-IR-101).

4 Capital Costs

5 Q. What is the capital budget for the DG projects?

6 A. \$2,093,753 in DG capital costs is included in the plant additions for the 2005 test  
7 year. See HECO-RWP-1801, page 6, project number P0001125.

8 Q. What is the basis for the forecasted capital investment for the DG projects?

9 A. The basis for the capital costs is provided on page 2 of HECO-R-701.

10 DG Non-Fuel O&M Expense

11 Q. What non-fuel O&M expenses are forecasted for DG in the test year?

12 A. Non-fuel O&M expenses for the nine units total \$1,466,000 on an annualized  
13 basis. These expenses are summarized on page 3 of HECO-R-701, and on  
14 HECO-R-603 and HECO-R-604. As mentioned earlier, HECO proposes to  
15 normalize the impact on O&M expenses by including the annual O&M expenses  
16 for the nine units in the 2005 test year revenue requirements.

17 DG Fuel Expense

18 Q. What are the estimated HECO DG fuel expenses for the 2005 test year?

19 A. Total annual expenses for consumed DG diesel fuel, including trucking, are  
20 estimated at \$1,039,000. These fuel expenses are reflected in HECO-R-404, page  
21 2, line 8, described in Mr. Sakuda's testimony.

22 Q. Please describe how these DG fuel expenses were estimated for the 2005 test year.

23 A. The HECO DG fuel costs used the May 2005 Waiau diesel fuel cost of  
24 \$79.4392/bbl as the base fuel cost and then added \$0.105/gal as the transportation  
25 adder for the trucking of the diesel fuel from the Chevron fuel terminal to the

1 individual DG project sites. (HECO's Inter-Island Industrial Fuel Oil and Diesel  
2 Fuel Supply Contract with Chevron, approved by Decision and Order No. 16142,  
3 filed on December 30, 1997 in Docket No. 97-0396, provides the bulk rate pricing  
4 for trucked diesel fuel picked up at the Chevron fuel terminals.) Annual  
5 consumed diesel expense was then calculated assuming 500 hours of operation per  
6 DG unit per year, with a heat rate of 9,833 Btu/kWh.

7 Q. Do HECO's fuel expenses for 2005 include a cost for DG diesel fuel inventory?

8 A. Yes. Mr. Sakuda addresses HECO fuel inventory and expenses in HECO RT-4.

9 Q. How did HECO estimate the volume of DG diesel fuel inventory for the test year?

10 A. The DG diesel fuel inventory volume included in HECO's 2005 test year revenue  
11 requirements is 500 barrels. This was based on HECO's assumption that fuel  
12 inventory would be 80% of the total fuel storage capacity available in the DG  
13 installations. Each of the nine DG units will have on-board diesel fuel storage of  
14 1,250 gallons. In addition, a 5,000 gallon supplemental diesel fuel storage tank  
15 was originally planned for installation at each of the three DG sites to provide

1     Response to Consumer Advocate's Position Regarding Annualization of DG O&M

2     Expenses

3     Q.   What amount of non-fuel DG O&M expense does the Consumer Advocate  
4           propose for inclusion in HECO's test year expenses?

5     A.   The Consumer Advocate proposes inclusion of O&M expenses for only the  
6           months the DG units are expected to be operational in 2005. According to the  
7           Consumer Advocate, this totals \$394,000 in non-fuel O&M expense, consisting of  
8           \$252,000 in DG rental expenses and \$142,000 in other O&M expenses. The  
9           Consumer Advocate calculated these amounts assuming the first DG site will be  
10          operational by the beginning of October, and the second and third DG sites will be  
11          on line by the beginning of November. See CA-T-1, page 31, line 12 to page 32,  
12          line 4 and CA Exhibit 101, Schedule C-7. These were the anticipated start dates  
13          indicated in HECO's May 5, 2005 update.

14    Q.   Are these still the anticipated start dates for the units?

15    A.   Not exactly. As stated earlier in my rebuttal testimony on page 5, lines 3-5, the  
16          first three DG units will be placed in service by the end of September, the second

17           three units in mid-October, and the final three units by the end of October. Thus,  
18           the actual 2005 DG expenses will be higher than what was assumed by the  
19           Consumer Advocate.

20    Q.   What is the basis for the Consumer Advocate's position?

21    A.   The Consumer Advocate alleges that new revenues from continuing load growth

1 Q. Is the Consumer Advocate's position reasonable?

2 A. No. As I pointed out earlier in this testimony, HECO has already ordered nine  
3 DG units for installation in 2005. The non-fuel O&M DG expenses will be  
4 incurred beginning in 2005 and these expenses will be ongoing. The \$394,000  
5 proposed by the Consumer Advocate amounts to only 27% of the annualized  
6 \$1,466,000 O&M expense that will be incurred for the nine DG units that will be  
7 placed in service in 2005. Comparing the amount proposed by the CA on a  
8 monthly basis to the amount HECO will incur for the remaining months of 2005  
9 when the units are in service, HECO's expenses will far exceed the amount  
10 proposed by the CA at the time that interim rates, if approved, go into effect in  
11 late 2005.

12 HECO-R-702 graphically illustrates this comparison, showing that if the  
13 CA's recommended cost recovery for DG expenses were adopted, HECO would  
14 not be able to recover \$85,460 of DG expenses every month. If HECO installs  
15 additional DG in 2006, which is highly likely given the 55-70 MW reserve  
16 capacity shortfall identified in HECO's 2005 AOS analysis, then the amount  
17 proposed by the Consumer Advocate is even farther off the mark compared to the  
18 actual costs that will be incurred by HECO. For example, if HECO were to install  
19 an additional nine DG units in 2006 at three sites that I describe later in rebuttal  
20 testimony, the amount of O&M expenses recommended by the Consumer  
21 Advocate amounts to less than 15% of actual DG costs incurred. (CA's figure of  
22 \$394,000 divided by double (for 18 units) the annual non-fuel O&M expenses  
23 shown in HECO-R-701, page 3.)

24 The gap between the Consumer Advocate's recommended O&M amount and

1 hope that revenues will grow and that utility costs in other areas will not increase.  
2 Furthermore, it should be stressed that the DG units are intended to be operated  
3 only intermittently when generating capacity reserves are low or system support is  
4 needed. Indeed, the fuel use assumptions for the 2005 test year are based on only  
5 500 hours of operation per unit per year. Revenues from the energy generated by  
6 the DG units will in no way pay for the expenses that will be incurred to have the  
7 units available to serve HECO's customers.

8 Q. Will the DG expenses be offset by expense reductions in some other area?

9 A. No. The O&M costs of the nine DG units are clearly new, additional expenses  
10 that will be incurred in HECO's operations. There will not be any corresponding  
11 expense reductions in other areas.

12 Q. What is the likelihood that HECO will install additional DG units beyond the test  
13 year, and has HECO done anything so far to implement such installations?

14 A. As mentioned earlier, the need for additional DG beyond the 2005 test year is  
15 evident given the 55-70 MW reserve capacity shortfall projected in HECO's 2005  
16 AOS analysis. We are actively conducting site assessment work for 2006 DG  
17 installations, although we haven't yet determined exactly how many DG units to  
18 pursue. It is very possible that we could install DG at three more HECO sites in  
19 2006.

20 Q. Please describe these efforts.

21 A. We have identified a number of HECO sites for installation of additional DG  
22 units, including two sites that were developed as candidate sites for the 2005  
23 installations. Those sites, Uwano Substation and Hoaeae Substation, were

1 Uwapo is pending issuance by the DOH. These two sites were also included in  
2 the DPP's July 1, 2005, letter mentioned earlier in my rebuttal testimony at page  
3 5. In that letter, the DPP determined that no discretionary land use permits are  
4 required for the Hoaeae and Uwapo sites. A portion of the Hoaeae site is within  
5 the Special Management Area ("SMA"), however the DPP advised that no SMA  
6 permit would be required provided that all proposed site improvements are  
7 installed outside the boundaries of the SMA.

8 In addition, we are currently conducting preliminary engineering for  
9 installation of DG units at HECO's Pole Yard located in Campbell Industrial Park.  
10 A fourth site, HECO's CEIP Substation, is another potential site for DG. We have  
11 also initiated discussion with the State Department of Transportation ("DOT")  
12 Airports Division about possibly siting temporary DG at the Airport Substation,  
13 which sits on land owned by the DOT. There are at least two other HECO  
14 substations that have available space and compatible zoning, which could also be  
15 considered in the future.

16 Q. Besides the Airport Substation, is HECO considering installation of DG at any  
17 other non-HECO sites?

18 A. Yes, although it is unlikely that any such projects would be implemented until  
19 2007 and beyond due to the complexities involved. For example, with the  
20 cooperation and support of the Department of Defense, we are commissioning an  
21 evaluation this year of the feasibility of developing HECO-owned DG on Oahu  
22 military installations.

23 Q. With the likely additional DG to be installed in 2006 and beyond, how would you  
24 characterize HECO's proposed annualized DG O&M amount for the 2005 test  
25 year?

1       A.    The normal ongoing level of DG expense is not only equal to the annualized  
2            amount proposed by HECO, but will probably exceed the annualized amount.  
3        HECO's proposed DG expense number is highly conservative from this

---

4            perspective.

5        Q.    How critical a role does DG play in HECO's plans?

6        A.    As described above, the DG will assume a critical role in mitigating HECO's  
7            reserve capacity shortfall. To this extent, the DG units are critical to the  
8            Company's ability to provide reliable service.

9        Q.    Is it reasonable to annualize the DG O&M expenses for the test year?

10       A.    Yes, especially considering that the O&M expenses make up a significant  
11            proportion of the overall costs of the DG mitigation measure compared to capital  
12            costs, and that additional DG installations beyond the 2005 test year are very  
13            likely. In short, it is certain that HECO will be incurring at least this level of  
14            annualized costs proposed by HECO in this proceeding to provide this critical DG  
15            service to its customers, and highly likely that higher costs will be incurred in  
16            2006 and beyond. The amount of O&M costs recommended by the Consumer  
17            Advocate is a small fraction of the actual expenses that will be incurred by HECO  
18            from the date that new rates would take effect.

19

20            2005 TEST YEAR ENERGY PROJECTS DEPARTMENT EXPENSE

21        Q.    What is the total Energy Projects Department expense for the 2005 test year?

22        A.    As reflected in Attachment 1A of HECO's May 5, 2005 update, the total updated  
23            expense for the Energy Projects Department is \$1,670,100, including capital  
24            project work, intercompany billables, charges to clearing, and non-project  
25            expense. The basis for this amount is shown in HECO-R-703.

1 Q. Please describe the HECO non-project expenses associated with the Energy  
2 Projects Department.

3 A. The updated net HECO non-project expense for annual labor, related overheads,  
4 and other expenses in the 2005 test year by the Energy Projects Department is  
5 \$451,802. See HECO-R-703, lines 13 and 15. Standard company-wide labor  
6 rates for the respective labor classes were used to calculate the labor expenses.

7 The updated department costs for the 2005 test year reflect a staffing level  
8 of nine utility personnel: a department manager, secretary, budget/statistical  
9 analyst, and six senior technical service engineers. One senior technical services  
10 engineer was added to the department in April 2005. However, two staff members  
11 are based on the neighbor islands – one on Maui and one on the Big Island. The  
12 costs for MECO and HELCO, both project and non-project costs, are billable  
13 charges to MECO and HELCO and, therefore, are not included in the net  
14 department non-project expense above.

15 Q. Was the new engineer added in April 2005 included in HECO's test year filing?

16 A. No. HECO's rate case filing in November 2004 assumed an Energy Projects  
17 Department staffing level of eight personnel. This was the staffing level of the  
18 department at year end 2004.

19 Q. Please explain the basis for adding the additional engineer in the Energy Projects  
20 Department.

21 A. The additional engineering position was filled in April 2005 primarily to bolster  
22 the department's ability to develop and implement the Oahu DG projects that are  
23 included in the 2005 test year, and to allow for stepped-up DG development in the  
24 future. A decision had been made by HECO in the first quarter of 2005 to  
25 immediately implement installation of DG at HECO sites to mitigate the HECO

1 reserve capacity shortfall situation. Even with the delays to HECO's proposed  
2 CHP program, the DG effort resulted in a net increase in the department's  
3 workload, and this will continue to be the case going into the future. This is due to  
4 the fact that the department continues to work on other ongoing projects and  
5 programs, including support of HECO's participation in the Distributed  
6 Generation Docket No. 03-0371, evaluation of other DG applications and  
7 technologies, and performing billable work for MECO and HELCO.

8 Q. From an accounting standpoint, what is the nature of the additional engineer's  
9 work?

10 A. The additional engineer primarily performs capital project work, as he is assigned  
11 on nearly a full-time basis to implement the DG projects at HECO. He does  
12 perform a very limited amount of billable work in support of the Maui and Big

- 1           2)    DG Non-Fuel O&M Expense               \$1,466,000  
2           3)    Energy Projects Dept Non-Project Expense    \$451,802.

3                   These proposals are reasonable and are fully supported by the testimony and  
4                   exhibits presented by HECO.

5       Q.    Does this conclude your testimony?

6       A.    Yes, it does.

7

8

9

10

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

HAWAIIAN ELECTRIC COMPANY, INC.  
2005 TEST YEAR

**SUMMARY OF DG/CHP CAPITAL, REVENUES, AND COSTS**

			<u>2005</u>
1	DG/CHP CAPITAL	\$000	
2	DG Capital		\$2,093.8
3	CHP System Capital		0.0
4			
5	DG INFORMATION		
6	DG Capacity Installed in 2005	MW	14.8
7	DG Generated Energy	MWH	7,380.0
8	Non-fuel Expenses related to DG	\$000	\$1,466.0
9			
10			
11			
12	UPDATED CHP SYSTEM		
13	CHP Generating Capacity	MW	0.0
14	CHP Generated Energy	MWH	0.0
15	Revenues related to CHP	\$	0.0
16	Expenses related to CHP	\$	0.0
17			
18			
19			
20			
21			
22	Note: DG costs are based on 12-months of operation of nine units,		
23	with (3) 1.64 MW units at each of three HECO sites.		

HAWAIIAN ELECTRIC COMPANY, INC.

2005 TEST YEAR

**2005 CAPITAL COSTS FOR DG AND UTILITY CHP**

	2005 (\$000)
<b>DG Capital Work (\$000)</b>	
HECO Engineering, construction and overheads	\$202.6
Outside Engineering work	\$26.1
Transformers, fuel tank and other equipment	\$199.5
Outside construction and construction material	\$201.0
	-----
Capital Cost per Site with 3-Units:	\$629.2
	=====
Capital Cost for Three (3) Sites:	\$1,887.7
PI system data monitoring software: <sup>1</sup>	<u>\$206.0</u>
<b>Total DG capital for 2005:</b>	<b>\$2,093.8</b>
<b>HECO CHP Capital Work (\$000)<sup>2</sup></b>	
No CHP projects to be built in 2005	\$0.0
	=====
<b>Total DG/CHP capital for 2005:</b>	<b>\$2,093.8</b>
<u>Notes</u>	
1. DG data monitoring software is a one-time cost.	
2. CHP projects are in design in 2005 with construction in 2006 pending PUC approvals.	

HAWAIIAN ELECTRIC COMPANY, INC.  
2005 TEST YEAR

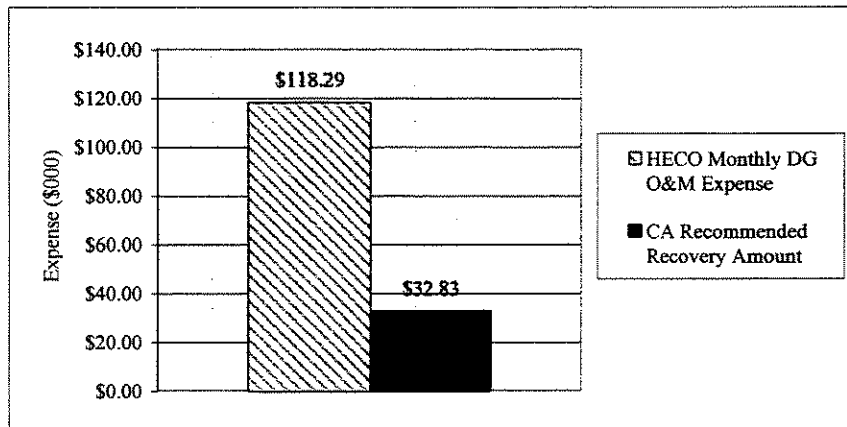
**DETAILED ESTIMATE OF DG NON-FUEL O&M COSTS**

		Monthly	Annual
	MONTHLY OPERATING COSTS	(\$000)	(\$000)
1	DG unit rental: \$152,000 per unit per year x 9-units	\$114.00	\$1,368.0
2	Phone line lease per site	\$1.89	\$22.7
3	DG unit monitoring and coordination work	\$1.80	\$21.6
4	Site security & on-site escort work	<u>\$0.60</u>	<u>\$7.2</u>
5	DG operating costs:	\$118.29	\$1,419.5
6			
7		Per Site	Annual
8	ANNUAL COSTS	(\$000)	(\$000)
9	Annual source test: \$5,000 per unit x 9-units	\$15.00	\$45.0
10	Non-Covered Source Air Permit Fee	<u>\$0.50</u>	<u>\$1.5</u>
11	DG air permit related costs:	\$15.50	\$46.5
12			
13			
14	<b>Total Annual Non-Fuel O&amp;M:</b>		<u><u>\$1,466.0</u></u>

HAWAIIAN ELECTRIC COMPANY, INC.  
2005 TEST YEAR

**COMPARISON OF MONTHLY NON-FUEL HECO DG O&M EXPENSES  
VS CONSUMER ADVOCATE PROPOSED COST RECOVERY**

1	ACTUAL DG OPERATING COSTS, HECO		
2	(not including source test and annual permit fee)	Monthly	
3		(\$000)	References
4	DG unit rental: \$152,000 per unit per year x 9-units	\$114.00	
5	Phone line lease per site	\$1.89	
6	DG unit monitoring and coordination work	\$1.80	
7	Site security & on-site escort work	<u>\$0.60</u>	
8	DG operating costs:	\$118.29	Source: HECO-R-701, page 3
9			
10			
11	PROPOSED COST RECOVERY, CONSUMER ADVOCATE		
12		Monthly	
13		(\$000)	References
14	Proposed annual non-fuel O&M: \$394.00	\$32.83	Source: CA Exhibit 101, Schedule C-7
15			
16	Difference	<u>\$85.46</u>	



HAWAIIAN ELECTRIC COMPANY, INC.  
2005 TEST YEAR

ENERGY PROJECTS DEPARTMENT

DEPARTMENT EXPENSES

	2005 TEST YEAR ESTIMATE (\$000)	References
1 Energy Projects Project Labor & Overhead Expenses		
2		
3 Labor Expenses	\$ 321.5	Source: HECO-RWP-703, page 1
4		
5 Overheads	\$ 381.0	Source: HECO-RWP-703, page 1
6		
7 InterCompany Billables to HELCO & MECO	\$ 450.4	Source: HECO-RWP-703, page 2
8		
9 Charges to Clearing	\$ 65.3	Source: HECO-RWP-703, page 3
10		
11 Energy Projects Dept Non-Project Expenses		
12		
13 Labor Expenses	\$ 255.9	Source: HECO-RWP-703, page 4
14		
15 Non-Labor Expenses	\$ 195.9	Source: HECO-RWP-703, page 4
16		
17 Total Energy Projects Department Expenses:	\$ 1,670.1	

REBUTTAL TESTIMONY OF  
STEPHEN K. YOSHIDA

MANAGER  
CONSTRUCTION AND MAINTENANCE DEPARTMENT  
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Transmission and Distribution ("T&D")  
Operation and Maintenance ("O&M") Expenses

INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen K. Yoshida and my business address is 820 Ward Avenue,  
Honolulu, Hawaii.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted written direct testimony, exhibits and supporting workpapers as  
HECO T-8.

Q. What is the scope of your rebuttal testimony?

A. My rebuttal testimony will:

- 1) Provide updated Transmission and Distribution ("T&D") Operation and  
Maintenance ("O&M") Expense test year estimates,
- 2) List and summarize those areas where HECO and the Consumer Advocate  
("CA") agree and/or the Department of Defense ("DOD") and HECO agree
- 3) List and summarize those areas where HECO and the CA disagree and/or

the DOD and HECO disagree, and

- 4) Discuss each area of disagreement.

HECO'S REBUTTAL POSITION

Q. What is HECO's rebuttal position regarding T&D O&M Expense for the 2005 test  
year?

A. HECO's rebuttal estimate for the 2005 test year is \$28,194,000; \$8,081,000 for  
Transmission O&M Expense and \$20,113,000 for Distribution O&M Expense as  
shown on HECO-R-800.

Q. How have these figures changed since your direct testimony T-8?

1 as shown on HECO-R-801. The rebuttal estimate for Transmission O&M expense  
2 is \$6,000 lower than the estimate in my direct testimony and the Distribution  
3 O&M Expense is \$19,000 lower than the estimate in my direct testimony.

4 Q. What is the reason for this change?

5 A. The adjustments made to the 2005 test year forecast were for the amortization of  
6 Ellipse maintenance buy-down fees. For further discussion on the adjustment,  
7 please refer to the testimony of Ms. Faye Yamauchi at HECO-RT-13.

8

9

AREAS OF AGREEMENT

10 Q. In what areas are the CA, DOD and HECO in agreement?

11 A. The CA, DOD and HECO agree on:

- 12 1) Standard Labor Rate Adjustment, and  
13 2) T&D materials inventory adjustment.

14 Q. Please explain the Standard Labor Rate Adjustment.

15 A. A difference of \$49,000 between the Transmission and Distribution O&M  
16 expenses in my rebuttal testimony and the O&M expense adjustments proposed  
17 by the CA relates to the Standard Labor Rate Adjustment, as shown on HECO-R-  
18 803, column B, line 2. As discussed by Ms. Faye Yamauchi in HECO RT-13,  
19 HECO, the Consumer Advocate and the DOD are in agreement with the Standard  
20 Labor Rate Adjustment. HECO is reflecting the adjustment as a separate line item  
21 in the results of operations. The Consumer Advocate attempted to allocate the

1 would be \$28,145,000.

2 Q. What is the CA's proposed adjustment with regards to T&D Materials Inventory  
3 as it applies to CA Adjustment B-2?

4 A. The CA proposes a total increase in Materials Inventory (Power Supply and T&D)  
5 of \$123,000. This is shown in Exhibit CA-101, Schedule B, Page 2, under  
6 column (C) on line 7.

7 Q. How did the CA determine the amount of this increase?

8 A. The CA used data provided by HECO in CA-IR-95 to adjust the 2005 test year  
9 Average Inventory Value provided in HECO-803 and recalculated the average  
10 using the December 31, 2004 actual inventory balances.

11 Q. What is the T&D portion of this increase and what is the resulting Average  
12 Inventory Value for the 2005 test year?

13 A. The T&D portion of this increase is \$83,000. The resulting T&D Average  
14 Inventory Value for the 2005 test year is \$4,932,000. Please refer to HECO-R-  
15 804, pages 1 – 3, for the derivation of these amounts.

16 Q. What is HECO's position regarding the proposed increase?

17 A. HECO agrees with the CA's proposed increase to the T&D Material Inventory  
18 value.

19

20

AREAS OF DISAGREEMENT

21 Q. With respect to the T&D expenses for which you are responsible, where do the  
22 CA and/or DOD disagree with HECO's normalized test year 2005 estimates?

23 A. There are two adjustments that the CA and/or DOD disagree with HECO in the  
24 T&D area all related to O&M expenses which result in the CA's test year estimates

1 HECO-R-802.

2 Q. What are the two adjustments that the CA and/or DOD and HECO disagree upon?

3 A. The two adjustments relate to software costs and average employee levels, as  
4 shown in HECO-R-803. The CA/DOD is proposing a \$35,000 reduction for  
5 software costs, whereas, HECO is proposing a \$25,000 reduction. The CA/DOD  
6 is proposing a \$321,000 reduction for average employee levels. Please refer to  
7 CA-101, Schedule C21 and DOD T-1, DOD-118. HECO disagrees with this  
8 proposed adjustment.

9 Software costs

10 Q. What is the CA's proposed adjustment with regards to T&D Expense as it applies  
11 to the fee paid by HECO to buy down the cost of the annual Ellipse maintenance  
12 fee?

13 A. The CA's proposed adjustment removes the Ellipse software upgrade amortization  
14 and the Ellipse buy-down fee amortization from T&D O&M expenses. CA-T-2,  
15 page 40, lines 11 – 15, and CA-101, Schedule C, page 4, column G, lines 6 and 7.  
16 The CA proposes a reduction in Transmission Expense of \$9,000 and a reduction  
17 in Distribution Expense of \$26,000. The total reduction in T&D Expense is  
18 \$35,000, as shown on HECO-R-803, column B, line 1.

19 Q. What is the CA's reason for proposing this adjustment?

20 A. The CA would remove the cost upgrading the software from the 2005 test year  
21 because the upgrade will not take place in 2005. In addition, the CA proposes to  
22 remove Ellipse buy-down fee amortization because the amortization period will  
23 end five months after the end of the 2005 test year. CA-T-2, pages 41 – 43.

24 Q. What is HECO's position regarding these proposed reductions?

25 A. As noted earlier in this rebuttal testimony, HECO agrees with removing \$25,000

5 What is the C.A.'s proposed adjustment with regards to T.D. Expenses as it applies

7 A. The CA proposes a reduction in Transmission Expense of \$135,000 and a  
8 reduction in Distribution Expense of \$186,000. CA-101, Schedule C, page 3,  
9 column G, lines 6 and 7. The total reduction in T&D Expense is \$321,000, as  
0 shown on HECO-R-803, column B, line 3.

12 A. The CA used data provided by HECO in DOD/HECO IR-8-8 page 5, to identify  
13 the O&M expenses for the "open" positions that impact T&D expenses and took

1 Q. With respect to Transmission and Distribution, which departments will be affected  
2 by the CA's proposed adjustment?

A. The primary Departments are Construction & Maintenance and System Operation. The staffing for the Support Services Department and the Energy Delivery Process Engineering Department will also be affected. I will discuss the effect of the proposed adjustment on each department.

## 7 Construction & Maintenance

8 Q. What was the direct testimony for the 2005 test year staffing count for the  
9 Construction and Maintenance Department (C&M)?

10       A.    The direct testimony staffing count for C&M was 220, as shown in HECO-825  
11           and HECO-R-805, column B, line 8.

12 O. What was the actual staffing count for the C&M at the beginning of 2005?

13 A. The staffing count at 1/1/05 for C&M was 219, with two open positions, as  
14 indicated in HECO-R-805, columns C and D, line 8. These open positions were a  
15 primary troubleman (PTM) and a cable splicer. They were identified in HECO's  
16 response to HECO/DOD-IR-8-8, page 6.

17 O. What is the status of the two open positions?

18       A.    The two open positions were both filled in March 2005, as shown in HECO-RWP-  
19           805, page 2, column F and G, line 1 for the PTM and line 7 for the cable splicer.  
20           HECO's response to HECO/DOD-IR-8-8, page 6 also shows that hiring for these  
21           took place in March 2005.

1 Q. Which positions are open?

2 A. The positions are one resource planner, one planning administrator, two PTM  
3 apprentices and one truck driver

4 Q. What is the status of the five open positions?

5 A. The formal hiring process is underway for each of the positions. HECO-RWP-  
6 805, pages 4 - 6, column G summarizes the current status of the hiring process for  
7 each position. HECO anticipates filling all five positions by the end of 2005.

8 Q. What is HECO's projected staffing count for C&M at the end of the year?

9 A. The projected staffing count at the end of the year for C&M is 221, as indicated in  
10 HECO-R-805, column J, line 8.

11 Q. Has the anticipated year-end staffing count of 221 positions changed from the  
12 staffing count used to determine the 2005 test year estimate for C&M?

13 A. No. The year-end staffing count remains unchanged. As mentioned at HECO T-  
14 8, page 18 of 22, line 20, the 220 employees for C&M represents an average  
15 staffing level

---

16 Q. Please explain the difference between the year-end total of 221 and the average  
17 staffing level of 220.

18 A. The year-end total of 221 was used in calculating the average staffing level of 220  
19 as shown in CA-IR-508, page 2 of 7. For further discussion on the computation of  
20 the average staffing level, please refer to HECO T-16, page 25 of 28, lines 21-25.

21 System Operation

22 Q. What was the direct testimony for the 2005 test year staffing count for the System  
23 Operation Department?

24 A. The direct testimony staffing count for System Operation was 109, as shown in  
25 HECO-825 and HECO-R-806, column B, line 9.

1 Q. What was the actual staffing count for System Operation at the beginning of  
2 2005?

3 A. The staffing count at 1/1/05 for System Operation was 100, with nine open  
4 positions. There was one position in Administration, one in Communications,  
5 three in Operating Engineering, three and one in the Substation Division, as  
6 indicated in HECO-R-806, column C and D. All of these positions were  
7 identified in HECO's response to HECO/DOD-IR-8-8, page 6.

8 Q. What is the status of the nine open positions?

9 A. Six of the nine positions have been filled, as shown in HECO/DOD-IR-8-8, page  
10 6 and HECO-R-806, column E. The remaining three positions, a systems analyst,  
11 a load dispatcher and a trouble dispatcher, are projected to be filled in 2005 by the  
12 dates noted in HECO-RWP-806, column E and G.

13 Q. What is the current staffing count for System Operation?

14 A. The current staffing count as of 7/26/05 for System Operation is 108, as shown in  
15 HECO-R-806, column G, line 9. There are 13 positions open and five projected  
16 reductions resulting in a net count of eight open positions, as noted in HECO-R-  
17 806, column H and I. There are four open positions in Operating Engineering,  
18 eight open positions in Operating Division, and one position in Relay, as shown in  
19 HECO-R-806, column H. The five reductions are the result of 1 promotion and 4  
20 retirements in the Operating Division, as noted in HECO-R-806, column I.

21 Q. What is the status of the eight open positions?

806 indicates an EFMS Tech position currently open, the position that was open as of 1/1/05 staffing count was filled during February 2005. The EFMS Tech position that is currently open subsequently became vacant due to an employee transfer in June 2005.

5 Q. What is HECO's projected staffing count for System Operation at the end of  
6 2005?

7 A The projected staffing count at the end of the year for System Operation is 116 as

8 indicated in HECO-R-806, column J.

9 Q. Please explain the increase between the 2005 test year staffing count of 109  
10 positions and projected year-end position of 116 positions?

11 A. The Chief Dispatcher, Switching Coordinator, System Analyst, Trouble

1 that are projected to retire within the next 6 months is 10 years. With the loss of  
2 these individuals, the junior, less experienced personnel will be left with the  
3 responsibility of operating the system. Currently, the average years of service for  
4 Trouble Dispatchers are 1 year 6 months and the average years of service for Load  
5 Dispatchers are 1 year 8 months. With the addition of the new Energy  
6 Management System (EMS), HECO will have the capability to train these  
7 dispatchers so that they can start developing the skills and knowledge that will be  
8 required to operate the system in the future. The new Training Administrator will  
9 provide the resources necessary to do this training on an ongoing basis.

10 3. *Trouble Dispatcher* – Over the next few years, the Operating Division  
11 of the System Operation Department will be losing individuals with many years of  
12 experience. The average years of service for the four Supervising Load  
13 Dispatchers that are projected to retire within the next 6 months is 10 years. With  
14 the loss of these individuals, the junior, less experienced personnel will be left  
15 with the responsibility of operating the system. Currently, the average years of  
16 service for Trouble Dispatchers are 1 year 6 months and the average years of  
17 service for Load Dispatchers are 1 year 8 months. The Trouble Dispatcher is the  
18 entry level position that will eventually provide the line of progression to Load  
19 Dispatcher and to Supervising Load Dispatcher, and will provide shift coverage to  
20 allow for simultaneous ongoing training

21 4. *Switching Coordinator* - The workload has almost doubled in that the  
22 number of holdoffs that are written total greater than 4,500+. A holdoff is the  
23 authorization officially issued to a specific person at his request, or his  
24 supervisor's, to work on specific equipment, circuit or circuit segment, which is  
25 inherently too hazardous to work while in service. The equipment or circuit must

1 be de-energized (disconnected) in a prescribed manner and placed in a safe  
2 condition to work on, and which shall remain so until released. The electrical  
3 system is more complex with some switching orders requiring over 100 steps in  
4 order to provide a safe clearance area. HECO has already done much to minimize  
5 the number of errors in the switching orders, however, the increased workload and  
6 the need to have these orders written accurately and safely necessitates hiring a  
7 new person.

8           5. *System Coordinator* - The System Coordinator position is critical in  
9 handling customer complaints, property damage claims and technical  
10 investigations regarding outages. The position was left vacant due to hiring  
11 constraints and needs to be filled to allow the department to address customer  
12 service issues in a timely, consistent manner.

13           6. *Operations Engineer* - This position is necessary to address reliability  
14 issues, perform additional operation contingency analyses when incidents occur  
15 and to prepare for the retirement of an incumbent in the position. Other  
16 responsibilities include managing the information that will be processed from the  
17 OMS and the EMS.

18           7. *Systems Analyst* - This position is not an addition to the section but will  
19 replace the Analyst that left the division in 2000. The basis for the support of the  
20 EMS and the OMS in the studies that were prepared for the project was based on  
21 having this individual in the organization to provide the basic support. HECO has  
22 indicated in response to Information Requests for the EMS and OMS projects that  
23 no new positions were being added to support the system; however, there is a need  
24 to get back to the previous staffing level in order to provide sufficient support for  
25 these systems.

1 Q. Please explain why these new positions were not in the Test Year forecast.

2 A.. The Test Year forecast was completed in March 2004. Beginning in late

3 December 2004/early January 2005, well beyond the time of the Test Year forecast.

4 Year forecast was established, System Operation undertook an effort to review  
5 future staffing needs due to changing conditions. Much of this effort was an  
6 evolving process initially driven by the unforecasted retirements of 4 System Load  
7 Dispatchers which as stated above, would leave us with less experienced personnel  
8 responsible for operating the system. Once the assessment was made and  
9 positions identified, internal procedures were followed to obtain approval for these  
10

1 HECO/DOD-IR-8-8 for further details of the open positions.

2 Q. What is the status of the eight open positions?

3 A. Two of the eight positions have been filled, as shown in HECO/DOD-IR-8-8 and  
4 HECO-RWP-807, column G, pages 1 – 2 of 6. The remaining six positions are  
5 projected to be filled by the dates noted in HECO-RWP-807, column G, pages 3 –  
6 4 of 6.

7 Q. What is the current staffing count for EDP Engineering?

8 A. The current staffing count as of 7/26/05 for EDP Engineering is 82, as shown in  
9 HECO-R-807, column G. There are eight positions open, as noted in HECO-R-  
10 807, column H.

11 Q. What is the status of the eight open positions?

12 A. The eight positions are projected to be filled in 2005 on the dates indicated in  
13 HECO-RWP-807, column G, pages 3 – 4 of 6.

14 Q. What is HECO's projected staffing count for EDP Engineering at the end of the  
15 year?

16 A. The projected staffing count at the end of the year for EDP Engineering is 90, as  
17 indicated in HECO-R-807, column J.

18 Q. What positions resulted in the increase between the direct testimony and projected  
19 year-end position?

20 A. There are four additional positions that were not included in the direct testimony  
21 for EDP Engineering.

22 Q. Please describe these new positions and explain why they need to be filled.

23 A. The four new positions are: a Telecommunications Engineer, Project Manager,  
24 Transmission & Distribution Engineer and Distribution Planning Engineer.

25 1. *Telecommunications Engineer* - One additional Telecommunications

1 (Telecom) Engineer position is added to meet the current and future workload  
2 requirements. Telecom has become a critical element in power system  
3 management and operations and strategic Company initiatives such as Asset  
4 Management, remote power quality monitoring (BMIs), Broadband Over Power  
5 Lines (BPL) for T&D operability, security, major capital projects, alternate energy  
6 solutions (CHP, DG, DSM), customer choices (BPL and remote metering) and  
7 internal telecommunications upgrades. By nature, the telecom equipment life  
8 cycle is short. As such, planning studies are needed to stay ahead of equipment  
9 obsolescence in order to maintain a reliable telecom system. The Telecom  
10 Section, unlike other areas of the Company where planning and design are  
11 separate functions, is responsible for both engineering and design of HECO's  
12 telecom systems as well as the planning of new systems, expansions and plant  
13 replacements.

14 2. *Project Manager* - The Project Management Division is adding another  
15 full-time Project Manager (PM) position to take on an additional multi-million  
16 dollar or complex capital projects. With a total of four full-time PM's (three  
17 existing and one additional position), more of these projects can be managed by  
18 HECO personnel who will be dedicated and specialized in managing projects.

19 3. *Transmission & Distribution Engineer and Distribution Planning*  
20 *Engineer* - The Distribution Planning section of the Transmission & Distribution  
21 Division requires the addition of one new position as a Distribution Planning  
22 Engineer. The section continues to support an increasing number of significant  
23 company initiatives. Distribution Planning Engineers are identified as distribution  
24 circuit owners in the Asset Management structure. Distribution Planning  
25 Engineers are involved in additional coordination, determining interconnection

standards and circuit load analysis and evaluations to insure the integrity of the distribution system. Customers are very dependent on continuous, reliable and usable power. The Distribution Planning Engineers must ensure that all customer power quality issues are properly addressed. The Distribution Reliability Team requires support from the Distribution Planning Engineers who provide justification for projects originated to address distribution system reliability concerns. In addition, there is an increased effort to balance existing loads making it much more of a challenge to determine how new customer loads can best be served. High land costs, its scarcity and public opposition have made acquisition of substation sites much more difficult. Considerable time and effort must be dedicated to justify the need for the substation and acquiring the land. The electrical distribution system is larger today and continues to expand. There are more distribution substation transformers and circuits that must be thoroughly reviewed each year as additional customers and equipment are connected.

Support Services

Q. What was the 2005 test year staffing count for Support Services?

A. The 2005 test year staffing count for Support Services was 81, as shown in HECO-1612, DOD/HECO-IR-8-8, page 3 and HECO-R-808, column B, line 7.

Q. What was the staffing count for Support Services at the beginning of the year?

A. The staffing count at 1/1/05 for Support Services was 81, as indicated in HECO-R-808, column C and D, line 7. Please refer to HECO/DOD-IR-8-8 for further details of the open positions.

Q. Were there any open positions at the beginning of the year?

A. No, Support Services was at their target staffing count.

Q. What is the current staffing count for Support Services?

1 A. The current staffing count as of 7/26/05 for Support Services is 80, as shown in  
2 HECO-R-808, column G. There are three positions open, as noted in HECO-R-  
3 808, column H.

4 Q. What is the status of the two open positions?

5 A. The three positions are projected to be filled in 2005 on the dates indicated in  
6 HECO-RWP-808, column G, pages 3 – 4 of 6.

7 Q. What is HECO's projected staffing count for Support Services at the end of the  
8 year?

9 A. The projected staffing count at the end of the year for Support Services is 83, as  
10 indicated in HECO-R-808, column J.

11 Q. What positions resulted in the increase between the direct testimony and projected  
12 year-end position?

13 A. There are two additional positions that were not included in the direct testimony

14 ~~for Support Services~~

---

15 Q. Please describe these new positions and explain why they need to be filled.

16 A. The two new positions are: a Purchasing Clerk and Senior Contract Administrator.

17 1. *Purchasing Clerk* - The additional Clerk position was considered do  
18 to the increased demand for clerical support, such as projects, coverage for clerks  
19 assigned to over-classification (buyer positions), and critical assignments. For  
20 example, it is likely or supplier files will need to be updated to accommodate an  
21 increase in State excise tax, which will be a significant undertaking.

22 2. *Senior Contract Administrator* - The Senior Contract Administrator  
23 position is an essential component to creating a centralized Contract

1 Senior Contract Administrator would be the program lead to formalize contract  
2 administration policies and guidelines, develop standardized contract  
3 administration procedures, conduct training for Contract Administrator for HECO,  
4 MECO, and HELCO, and administer contract administration qualifications and  
5 certifications. The Senior Contract Administrator would also supervise the three  
6 full-time HECO Contract Administrators, who currently reside in Power Supply  
7 (2) and Energy Delivery (1). If/when it is determined that other process areas  
8 would create full-time Contract Administrator positions, those Contract  
9 Administrators could fall under the supervision of the Senior Contract  
10 Administrator. The contract administration group would be organized under  
11 HECO's Purchasing Division, and the Senior Contract Administrator would report  
12 to the Director of Purchasing Division.

13 Q. You've identified in your rebuttal testimony a number of new positions that were  
14 not included in the 2005 test year staffing count covered in your direct testimony,  
15 T-8. Does HECO propose any adjustment to T&D O&M Expenses with regards  
16 to these new positions?

17 A. No. HECO does not propose any adjustment to T&D O&M Expense due to  
18 staffing levels. However, it is HECO's position that all positions in the 2005 test  
19 year staffing count should be funded for the entire year.

20 Q. Please provide the reasons for this position.

21 A. First, as shown and explained above, HECO plans to meet the 2005 test year  
22 staffing estimates, and in fact, plans to exceed the test year forecast staffing.

23 Therefore, the full funding for the positions should be maintained.

24 In addition, funding for these positions is reasonable because the current level of  
25 T&D expense indicates that HECO will equal and possibly exceed the 2005 test

1           year estimate. The actual T&D O&M expenses through 6/30/05 is \$14,652,000.  
2           Based on this spending pattern, HECO projects T&D O&M expenses to equal or  
3           exceed the original test year estimate of \$28,219,000.

4       Q.   Can you provide an example of where the test year estimate is likely to be  
5           exceeded?

6       A.   The Corrective Maintenance program is the primary program where response to  
7           cable failures is budgeted. Unfortunately, our costs to respond to cable failures are  
8           exceeding our forecast. Through 6/30/05 we have expended \$722,000 more than  
9           we forecasted. We are not expecting a reduction in these costs for the remainder of  
10          the year as typically corrective maintenance cost increase due to bad weather  
11          during the winter months.

12          Spending overall for corrective and preventative maintenance has increased  
13          significantly since 2000. The O&M expenses have increased from \$4,517,828 in  
14          2000 to \$13,139,452 in 2004. The 2005 test year O&M expense estimate for these  
15          accounts is \$13,276,902. Please refer to CA-IR-64, Attachment A for the actual  
16          costs for 2000 – 2004, 2004 budget and 2005 test year estimates for these  
17          programs.

18       Q.   Does HECO expect this level of expenditures for these programs to continue into  
19           the future?

20       A.   Yes. As I explained in HECO T-8 Direct Testimony, our facilities are aging with  
21           cable faults at the top of the list of failure causes. As we noted above, we are not  
22           yet experiencing the expected benefits of our cable replacement programs.

23       Q.   Given that HECO expects to exceed the 2005 test year forecast and the expectation  
24           that these costs will continue into the future, is HECO proposing any increase to  
25           its T&D Expense estimate to account for these factors?

1 A. No. HECO does not propose any adjustment to T&D O&M Expense for these  
2 projected cost increases. While HECO is not proposing to increase the T&D  
3 Expense estimate to cover these costs we do require full funding for the staff  
4 positions noted above to operate and maintain our facilities to manage and mitigate  
5 these costs.

6

7

SUMMARY

8

Q. Please summarize your rebuttal testimony.

9

A. As shown in HECO-R-800, HECO's revised test year estimates for Transmission  
10 O&M Expense are \$8,081,000 and Distribution O&M Expense is \$20,113,000 for  
11 a total T&D O&M Expense estimate of \$28,194,000. The revised T&D Average  
12 Material Inventory estimate for Distribution is \$4,000,000.

Hawaiian Electric Company, Inc.  
REBUTTAL 2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION  
OPERATIONS & MAINTENANCE EXPENSE  
(\$ Thousands)

	<u>2005</u> <u>REBUTTAL</u>
1     Transmission O&M Expense	\$     8,081
2     Distribution O&M Expense	<u>\$    20,113</u>
3     Total	<u><u>\$    28,194</u></u>

Source:

For lines 1 and 2: HECO-RT-801.

Note:

Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.  
REBUTTAL 2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION  
OPERATIONS & MAINTENANCE EXPENSE  
(\$ Thousands)

	(A)	(B)	(C)
	<u>DIRECT</u>	<u>ADJ</u>	<u>REBUTTAL</u>
1 Transmission O&M Expense	\$ 8,087	\$ (6)	\$ 8,081
2 Distribution O&M Expense	<u>\$ 20,132</u>	<u>\$ (19)</u>	<u>\$ 20,113</u>
3 Total	<u>\$ 28,219</u>	<u>\$ (25)</u>	<u>\$ 28,194</u>

Source:

Column A, Lines 1 and 2: HECO-802.

Column B, Lines 1 and 2: HECO-1604, page 17 of 18.

Note:

Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.  
REBUTTAL 2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION  
OPERATIONS & MAINTENANCE EXPENSE

HECO vs. CA Differences  
(\$ Thousands)

	(A)	(B)	(C)	(D)	(E)
	<u>DIRECT</u>	<u>ADJ</u>	<u>REBUTTAL</u>	<u>CA TEST YEAR</u>	<u>DIFFERENCE (HECO-CA)</u>
1 Transmission O&M Expense	\$ 8,087	\$ (6)	\$ 8,081	\$ 7,929	\$ 152
2 Distribution O&M Expense	\$ 20,132	\$ (19)	\$ 20,113	\$ 19,885	\$ 228
3 Total	\$ 28,219	\$ (25)	\$ 28,194	\$ 27,814	\$ 380

Source:

Column A: HECO-802.

Column B: HECO-1604.

Column C: HECO-R-800.

Column D: Exhibit CA-101, Schedule C, page 1 of 5.

Column E = C - D

Note:

Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.

REBUTTAL 2005 TESTIMONY

TRANSMISSION AND DISTRIBUTION  
OPERATIONS & MAINTENANCE EXPENSE  
Summary of HECO and CA Differences  
(\$ Thousands)

	(A)	(B)	(C)
	<u>HECO REBUTTAL</u>	<u>CA TESTIMONY</u>	<u>HECO - CA DIFFERENCE</u>
1 Software costs	\$ (25)	\$ (35)	\$ 10
2 Standard labor rates and overtime pay	\$ -	\$ (49)	\$ 49
3 Average employee levels	<u>\$ -</u>	<u>\$ (321)</u>	<u>\$ 321</u>
	<u>\$ (25)</u>	<u>\$ (405)</u>	<u>\$ 380</u>

Hawaiian Electric Company, Inc.  
Materials & Supplies Inventory

(\$ in thousands)

	(A)	(B)	(C)	(D)	(E)
	<u>Direct Testimony</u>	<u>12/31/04</u>	<u>12/31/05</u>	<u>Rebuttal</u>	<u>Variance</u>
1 Production	5,329	5,489	5,294	5,392	63
2 T&D	5,192	5,554	5,031	5,293	101
<hr/>					
3 Total Materials & Supplies	10,521	11,043	10,325	10,684	163
4 Adjustment to Materials & Supplies	<u>(536)</u>	<u>(618)</u>	<u>(536)</u>	<u>(577)</u>	<u>(41)</u>
5 Adjusted Total for Materials & Supplies	<u>9,984</u>	<u>10,425</u>	<u>9,789</u>	<u>10,107</u>	<u>123</u>

Source:

Column A and D taken from HECO-1000

Hawaiian Electric Company, Inc.  
Materials & Supplies Inventory - Production  
(\$ in thousands)

	(A)	(B)	(C)	(D)	(E)
	<u>Direct</u> <u>Testimony</u>	<u>12/31/2004</u>	<u>12/31/2005</u>	<u>Rebuttal</u>	<u>Variance</u>
1 Production	5,329	5,489	5,294	5,392	63
2 Adjustment	<u>(192)</u>	<u>(239)</u>	<u>(192)</u>	<u>(216)</u>	<u>(24)</u>
Adjusted					

Hawaiian Electric Company, Inc.  
Materials & Supplies Inventory - T&D  
(\$ in thousands)

	(A)	(B)	(C)	(D)	(E)
	<u>Direct Testimony</u>	<u>12/31/2004</u>	<u>12/31/2005</u>	<u>Rebuttal</u>	<u>Variance</u>
1 T&D	5,192	<u>5,554</u>	<u>5,031</u>	<u>5,293</u>	<u>101</u>
2 Adjustment	<u>(343)</u>	<u>(379)</u>	<u>(343)</u>	<u>(361)</u>	<u>(18)</u>
3 Adjusted Total	<u>4,849</u>	<u>5,175</u>	<u>4,688</u>	<u>4,932</u>	<u>83</u>

Source:

Column A and C, Line 1: HECO-1903.

Column B, Line 1: CA-IR-95, page 3.

Column D = (B + C)/2

Column E = D - A

Note:

Figures may not total exactly due to rounding.

J

Projected  
12/31/05

7

13

14

2

8

26

125

26

221

HECO-R-805

DOCKET NO. 04-0113

Hawaiian Electric Company, Inc.  
REBUTTAL 2005 TEST YEAR

SYSTEM OPERATION

A	B	C	D	E	F	G	H	I	J
	<u>Direct</u> <u>Testimony</u>	<u>Actual</u> <u>1/1/05</u>	<u>Open</u> <u>1/1/05</u>	<u>Additions</u>	<u>Reductions</u>	<u>Actual</u> <u>7/26/05</u>	<u>Additions</u>	<u>Reductions</u>	<u>Projected</u> <u>12/31/05</u>
1 Administration	6	5	1	2	(1)	6	0	0	6
2 Communications	8	7	1	3	(2)	8	0	0	8
Construction									
3 Management	3	3	0	0	0	3	0	0	3
Operating									
4 Engineering	13	10	3	3	(3)	10	4	0	14
Instrument &									
5 Control	9	9	0	1	(1)	9	0	0	9
6 Operating Division	23	20	3	6	(1)	25	8	(5)	28
7 Relay	10	10	0	2	(3)	9	1	0	10
8 Substation	37	36	1	7	(5)	38	0	0	38
9 Total	109	100	9	24	(16)	108	13	(5)	116

Hawaiian Electric Company, Inc.  
REBUTTAL 2005 TEST YEAR

ENGINEERING

A	B	C	D	E	F	G	H	I	J
	Direct Testimony	Actual 1/1/05	Open 1/1/05	Additions	Reductions	Actual 7/26/05	Additions	Reductions	Projected 12/31/05
1	Administration	7	0	0	0	7	0	0	7
2	Transmission & Distribution	23	2	3	(2)	22	4	0	26
3	Project Management	8	3	1	0	6	1	0	7
4	Structural	18	1	1	(1)	17	1	0	18
	Substation, Protection &								
5	Telecommunications	21	1	2	(1)	21	1	0	22
6	Technical Services	10	9	1	0	9	1	0	10
7	Total	87	79	8	7	(4)	82	8	90

HECO-R-807  
DOCKET NO. 04-0113  
PAGE 1 OF 1

Hawaiian Electric Company, Inc.  
REBUTTAL 2005 TEST YEAR

SUPPORT SERVICES

A	B	C	D	E	F	G	H	I	J
	Direct Testimony	Actual 1/1/05	Open 1/1/05	Additions	Reductions	Actual 7/26/05	Additions	Reductions	Projected 12/31/05
1 Administration	5	5	0	0	0	5	0	0	5
2 Purchasing	10	11	0	0	0	11	1	0	12
Materials									
3 Management	28	27	0	1	0	28	0	0	28
4 Fleet Services	25	25	0	2	(4)	23	2	0	25
Electrical & 5 Welding Services	13	13	0	0	0	13	0	0	13
6 Total	81	81	0	3	(4)	80	3	0	83

HECO-R-808  
DOCKET NO. 04-0113  
PAGE 1 OF 1

REBUTTAL TESTIMONY OF  
DARREN S. YAMAMOTO

MANAGER  
CUSTOMER SERVICE  
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Customer Accounts Expense  
Customer Deposits  
Interest on Customer Deposits  
Revenue Lag Days

INTRODUCTION

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15  
16  
17  
18  
19  
20  
21

Q. Please state your name and business address.

A. My name is Darren S. Yamamoto and my business address is 900 Richard Street, Honolulu, Hawaii. I am the Customer Service Department Manager of Hawaiian Electric Company, Inc. ("HECO"). I replaced Amy Ejercito as the Customer Service Manager in December 2004. Ms. Ejercito was promoted to Vice President of Corporate Excellence on January 1, 2005.

Q. Are you replacing Ms. Ejercito as the witness for Customer Accounts Expense, Customer Deposits and Interest on Customer Deposits and Revenue Lag Days?

A. Yes. I am adopting Ms. Ejercito's testimony marked as HECO T-9. My experience and educational background are listed in HECO-R-900.

Q. What is the scope of your rebuttal testimony?

A. My rebuttal testimony will:

- 1) Present HECO's rebuttal position with respect to test year 2005 estimates for Customer Accounts Expense including test year estimates for Customer Deposit Balance, Interest on Customer Deposits and Revenue Lag Days.
- 2) List and summarize the areas of agreement with the Consumer Advocate ("CA") and the Department of Defense ("DOD");
- 3) List and summarize the areas of disagreement with the CA and DOD; and
- 4) Discuss each area of disagreement.

REVISED CUSTOMER ACCOUNTS EXPENSE

Q. What was HECO's test year estimate of Customer Accounts Expense that was presented in direct testimony?

A. HECO's test year estimate of Customer Accounts Expense as provided in our

1 direct testimony was \$12,728,000 which includes \$1,292,000 for Uncollectible  
2 Accounts Expense at present rates as shown on Exhibit HECO-901, page 1,  
3 column labeled Test Year 2005. The DOD agreed with HECO direct testimony  
4 for Uncollectible Accounts Expense as shown on Exhibit DOD-104, Page 1, Line  
5 11.

6 Q. What was the CA's position on Uncollectible Accounts Expense?

7 A. The CA's proposed Uncollectible Accounts Expense is \$1,183,000 at present rates  
8 as shown on Exhibit CA-101, Schedule C-13, Page 1, Line 3. This is based on the  
9 CA's proposed Uncollectible Factor (4-yr avg.) of 0.0946% as shown on Exhibit  
10 CA-101, Schedule C-13, Page 1, Line 2.

11 Q. Please comment on the CA's proposed adjustment.

12 A. While we do not agree with the CA's rationale underlying its proposed  
13 Uncollectible factor, for the purposes of this proceeding we will accept using a  
14 proposed Uncollectible Factor of 0.0946%. The Company's rebuttal position  
15 compared to those proposed by the CA and the DOD can be found on HECO-R-

---

16 901, Page 1, Line 6.

17 Q. What is HECO's revised test year estimate of Customer Accounts Expense?

18 A. HECO's revised test year estimate of Customer Accounts Expense is \$12,588,000  
19 which includes \$1,152,000 for Uncollectible Accounts at present rates. See  
20 HECO-R-901, Line 7, Column C and HECO-R-901, Line 6, Column C.

21 Q. Please comment on HECO's proposed rebuttal estimates for Customer Accounts  
22 Expense.

23 A. HECO's Customer Accounts Expense estimate for test year 2005 has been revised

1 at present rates.

2 Q. What is HECO's revised Uncollectible Accounts Expense estimate at present  
3 rates?

4 A. HECO's Uncollectible Accounts Expense estimate at present rates is \$1,152,000  
5 using the CA's proposed Uncollectible Factor of 0.0946%. This is \$140,000 less  
6 than the \$1,292,000 presented in direct testimony. HECO-R-903, page 1, Lines 1  
7 – 3 shows the calculation that reflects the lower Uncollectible Accounts Expense  
8 at present rates.

9 Q. Why is there a difference between the Uncollectible Accounts Expense estimate  
10 of HECO and the CA at present rates?

11 A. There is a difference between the Uncollectible Accounts Expense estimate  
12 because HECO and the CA have different sales revenue projections.

13

14 REVISED CUSTOMER DEPOSITS

15 Q. What was HECO's test year estimate for Customer Deposits that was presented in  
16 direct testimony?

17 A. HECO's test year estimate for Customer Deposits as provided in our direct  
18 testimony was \$6,262,000 as shown in HECO-902, Page 1.

19 Q. Is HECO revising the test year 2005 estimate for Customer Deposits?

20 A. Yes. HECO is revising the average test year Customer Deposit balance from  
21 \$6,262,000 to \$5,901,000.

22 Q. How is HECO's revised average test year balance of Customer Deposits derived?

23 A. The amount is updated based on the trued up recorded balance of 2004 as  
24 provided in HECO's response to CA-IR-95. The revised average 2005 test year  
25 Customer Deposits balance of \$5,901,000 is derived from a simple average of

1 year-end actual 2004 of \$5,066,000 and 2005 estimated customer deposit balance  
2 of \$6,735,000 respectively. See HECO-R-902.

3 Q. What are the positions of the CA and DOD on Customer Deposits?

4 A. Both the CA and DOD agree with HECO's revised Customer Deposit balance of  
5 \$5,901,000 as shown in CA-T-1, Page 98, Lines 20-22 and Page 99, Lines 1-3,  
6 and Exhibit CA-101, Schedule B-2, Page 1, Line 33, also in Exhibit DOD-103,  
7 Line 11.

8 Q. Please comment on the positions of the CA and the DOD.

9 A. HECO, the CA and the DOD are all in agreement with the adjusted average test  
10 year Customer Deposit balance of \$5,901,000.

11

12 INTEREST ON CUSTOMER DEPOSITS

13 O. Is HECO revising the test year 2005 estimate for Interest on Customer Deposits?

---

14 A. No. HECO is not revising the Interest on Customer Deposits of \$378,000 as  
15 shown in direct testimony, on HECO-903, Page 1, Line 13. The CA and the DOD  
16 did not propose any adjustments to the Interest on Customer Deposits as shown on  
17 Exhibit CA-101, Schedule C, Page 5, Line 15 and Exhibit DOD-104, Page 1, Line  
18 17.

19

20 REVISED REVENUE LAG DAYS

21 Q. What was HECO's test year estimate of Revenue Lag Days that was presented in  
22 direct testimony?

23 A. HECO's test year estimate of Revenue Lag Days as provided in our direct  
24 testimony was 38 days. See HECO T-9, Page 23, Lines 16 through 20.

25 Q. What are the positions of the CA and DOD on Revenue Lag Days.

1 A. Both the CA and DOD revised HECO's proposed test year Revenue Lag Days  
2 from 38 days to 37 days. See CA-T-1, Page 108, Lines 11 – 14 and DOD T-1,  
3 Page 17, Lines 14 – 17.

4 Q. Please comment on the positions of the CA and the DOD.

5 A. While we do not agree with the CA's and DOD's rationale underlining the  
6 proposed adjustment, for the purpose of this proceeding we will accept the  
7 Revenue Lag Days of 37 days.

8 Q. Is HECO revising the test year 2005 estimate for Revenue Lag Days?

9 A. Yes. HECO is revising the test year estimate from 38 days to 37 days.

10

11 STANDARD LABOR RATES AND OVERTIME PAY. CA ADJUSTMENT C-20

---

12 Q. What is the CA's proposed adjustment to Customer Accounts Expense with  
13 respect to the CA proposed Standard Labor Rates and Overtime Pay Adjustment?

14 A. The CA proposes a reduction in Customer Accounts Expense of \$25,000 as shown  
15 on HECO-R-904, Page 1, Column B, Line 2.

16 Q. What is HECO's position regarding these proposed reductions?

17 A. HECO agrees with the CA on the reduction of these costs per HECO/DOD-IR-9-  
18 18. As discussed by Ms. Faye Yamauchi in HECO RT-13, HECO, the Consumer  
19 Advocate and the DOD are in agreement with the Standard Labor Rate  
20 Adjustment. HECO is reflecting the adjustment as a separate line item in the  
21 results of operations. The Consumer Advocate attempted to allocate the total  
22 adjustment to each block of accounts, which is the reason for the apparent  
23 difference. (The DOD reflected the entire amount in A&G expenses.) HECO's  
24 Customer Accounts estimate, if reduced by the amount of the CA's proposed

1                   AREAS OF AGREEMENT BETWEEN HECO, CA AND THE DOD

2           Q.    In what areas are HECO, CA and DOD in agreement?

3           A.    As previously discussed, HECO, CA and DOD are now in agreement in the  
4                following areas:

- 5                1)    Revised Customer Accounts Expense with the exceptions of the Labor  
6                       Expense Adjustment and the use of present rates on the Uncollectible  
7                       Accounts Expense;  
8                2)    Revised Customer Deposits;  
9                3)    Interest on Customer Deposits;  
10               4)    Revised Revenue Lag Days; and  
11               5)    Revised Standard Labor Rate and Overtime Pay.

12

13                   AREAS OF DISAGREEMENT BETWEEN HECO, CA AND DOD

14          Q.    In what areas does the CA differ with HECO?

15          A.    The areas that the CA disagrees with HECO are:

- 16               1)    The CA recommends using Electric Sales Revenue at present rates as  
17                       compared to HECO using Electric Sales Revenue at proposed rates in  
18                       calculating the Uncollectible Accounts Expense amount. See Exhibit CA-  
19                       101, Schedule C-13, Page 1, Line 1. See HECO-R-903, Page 1, Line 4.  
20               2)    The CA proposes a labor expense adjustment. See HECO-R-904, Page 1,  
21                       Column B, Line 3.

22          Q.    In what areas does the DOD differ from HECO?

23          A.    The area that the DOD differs from HECO is:

- 24               1)    The DOD proposes a labor expense adjustment. See HECO-R-904, Page 2,  
25                       Column B, Line 2.

UNCOLLECTIBLE EXPENSE AT PROPOSED RATES

Q. Why does HECO use Electric Sales Revenue at proposed rates in the calculation of the Uncollectible Expense amount instead of using Electric Sales Revenue at present rates?

A. HECO uses Electric Sales Revenue at proposed rates because such a methodology is consistent with the methodology used in prior rate cases. HECO utilizes the "Percentage of Electric Sales Revenue" method, which has been applied to proposed rates in prior rate cases, and has been approved in previous Decision and Orders, including HECO's last rate case, in Docket No. 7766, Decision and Order No. 14412 dated December 11, 1995 and previously in Docket No. 6998, Decision and Order No. 11699 dated June 30, 1992. This method was also approved in the MECO Docket No. 97-0346, Decision and Order No. 16922 dated April 6, 1999 and in the HELCO Docket No. 99-0207, Decision and Order No. 18365 dated February 8, 2001.

Q. What is the "Percentage of Electric Sales Revenue" method that HECO uses?

A. HECO's "Percentage of Electric Sales Revenue" method calculates uncollectibles for a given period by multiplying electric sales revenue for that period by a net write-off percentage. The net write-off percentage (or factor) is determined by dividing the total net write-offs for the latest twelve months for which data is

available by the total electric sales revenue for the same period. HECO's

1       A.    The CA proposed an overall labor expense adjustment to HECO which impacts  
2           the Customer Service Department by a \$204,000 decrease. The DOD agrees with  
3           the CA's proposed labor expense adjustment. See HECO-R-904, Page 1, Column  
4           B, Line 3 and HECO-R-904, Page 2, Column B, Line 2.

5       Q.    Does HECO agree with the labor expense adjustment as it relates to the Customer  
6           Service Department proposed by the CA and the DOD?

7       A.    No. HECO does not agree with the labor expense adjustment as is relates to the

8           Customer Service Department proposed by the CA and the DOD. The DOD agrees with the

1 Q. What two positions are unfilled?

2 A. The Operations Analyst and the Director of Customer Account Services.

3 Q. When did these positions become vacant?

4 A. Both of these positions became vacant in May 2005.

5 Q. What is HECO doing to fill these positions?

6 A. In connection with filling these positions, HECO evaluated expected future needs  
7 so that the skill sets of the individuals who will fill the positions will match the  
8 Department's future requirements.

9 Q. What progress has been made in filling these positions?

10 A. The review of skill sets has been completed. The Operations Analyst position is currently being filled.

1       A.   HECO's 2005 test year Customer Accounts Expense as revised in this rebuttal  
2       testimony of \$12,588,000 reflects HECO's best estimate on the most currently  
3       available data. This reflects a reduction in the Uncollectible Accounts of  
4       \$140,000 from direct testimony. This reflects a reduction in the Uncollectible  
5       Factor from 0.13% to 0.0946%. The Revenue Lag Days will be 37 reduced from  
6       38 in direct testimony. The Customer Deposits will be \$5,901,000 down from  
7       \$6,262,000 in direct testimony and there is no change on Interest on Customer  
8       Deposits which will remain at \$378,000.

9       Q.   Does this conclude your testimony?

10      A.   Yes, it does.

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

HAWAIIAN ELECTRIC COMPANY, INC.

DARREN S. YAMAMOTO

---

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS: Hawaiian Electric Company, Inc.  
900 Richards Street, Honolulu, HI 96813

POSITION: Manager, Customer Service Department  
Hawaiian Electric Company, Inc.  
(December 2004 to present)

YEARS OF SERVICE: 20 Years

EDUCATION: University of Hawaii (1983), Bachelor of Business  
Administration, Finance

PREVIOUS POSITIONS: Director, Customer Field Services,  
Customer Service Department  
Hawaiian Electric Company, Inc.  
(September 2002 to December 2004)

Supervisor, Construction & Maintenance Department  
Hawaiian Electric Company, Inc.  
(November 1999 to September 2002)

Working Foreman,  
Construction & Maintenance Department  
Hawaiian Electric Company, Inc.  
(October 1995 to November 1999)

Transmission & Distribution Line Inspector,  
Construction & Maintenance Department  
Hawaiian Electric Company, Inc.  
(May 1994 to September 1995)

Linemen, Construction & Maintenance Department  
Hawaiian Electric Company, Inc.  
(August 1984 to May 1994)

HAWAIIAN ELECTRIC COMPANY, INC.  
CUSTOMER ACCOUNTS EXPENSE  
2005 TEST YEAR

(\$ THOUSANDS)

Line	CUSTOMER ACCOUNTS	(A)		(B)		(C)		(D)		(D)-(C)		(F)		(F)-(C)	
		Direct Testimony	Rebuttal Adjust-ments	Rebuttal Testimony	CA Testimony	HECO Rebuttal - CA Difference	DOD Testimony	HECO Rebuttal - DOD	Difference						
1	901.00 Supervision	930	0	930											
2	902.00 Meter Reading Expenses	2,524	0	2524											
3	903.00 Cust Records & Collection	7,982	0	7982											
4	905.00 Misc. Customer Accounts	0	0	0											
5	Subtotal	11,436	0	11,436	11,207	-229	11,232								-204
6	904.00 Uncollectible Accounts	1,292	-140	1,152	1,183	31	1,292	140							
7	Total Customer Account Expense	12,728	-140	12,588	12,390	-198	12,524	-64							

Note: Account 904-Uncollectible Account for 2005 test year is at present rates.

Source:

Col. (A): HECO-901, Page 1. See also HECO response to CA-IR-680, Page 2 for HECO-901 updated for 2004 recorded amounts.  
Col. (C), Line 6: HECO-R-903, Line 3.  
Col. (D), Line 5: On Exhibit CA-101, Schedule C, Page 1, the CA proposed Customer Accounts Total is shown as \$11,107K. The amount should be \$11,207K. The CA incorrectly reduced Customer Accounts by \$100K for the Green Power Program and to Account 910. See Exhibit CA-101, Schedule C-24. In the CA's response to HECO/CA-IR-213, the CA confirmed the posting error and that the \$100k reduction should have been posted to Customer Service Expense.  
Col. (D), Line 6: Exhibit CA-101, Schedule C, Page 1, Line 9.  
Col. (E): See HECO-R-904, Page 1.  
Col. (F), Lines 5 & 6: Exhibit DOD-104, Page 1.  
Col. (G): See HECO-R-904, Page 2.

HAWAIIAN ELECTRIC COMPANY, INC.  
CUSTOMER ACCOUNTS EXPENSE - LABOR AND NON-LABOR  
2005 TEST YEAR

		(\$ THOUSANDS)						
		(A)	(B)	(C)	(D)	(D)-(C) (E)	(F)	(F)-(C) (F)-(C)
LINE	CUSTOMER ACCOUNTS	Direct Testimony	Rebuttal Adjust- ments	Rebuttal Testimony	CA Testimony	HECO Rebuttal-CA Difference	DOD Testimony	HECO Rebuttal - DOD Difference
<u>Account 901 - Supervision</u>								
1	Labor	117		117				
2	Non-labor	<u>813</u>		<u>813</u>				
3	TOTAL	<u>930</u>	0	<u>930</u>	0	0	0	0
<u>Account 902 - Meter Reading</u>								
4	Labor	2,174		2,174				
5	Non-labor	<u>350</u>		<u>350</u>				
6	TOTAL	<u>2,524</u>	0	<u>2,524</u>	0	0	0	0
<u>Account 903 - Cust Rec. &amp; Collection</u>								
7	Labor	4,553		4,553	0	0		
8	Non-labor	<u>3,429</u>		<u>3,429</u>	0	0		
9	TOTAL	<u>7,982</u>	0	<u>7,982</u>	0	0	0	0
<u>Account 905 - Misc Cust Accts.</u>								
10	Labor	0		0	0	0	0	0
11	Non-labor	0		0		0		
12	TOTAL	0	0	0	0	0	0	0
<u>Sub total 901,902,903,905</u>								
13	Labor	6,844	0	6,844	6,615	-229	6,640	-204
14	Non-Labor	<u>4,592</u>	0	<u>4,592</u>	<u>4,592</u>	0	<u>4,592</u>	0
15	TOTAL	<u>11,436</u>	0	<u>11,436</u>	<u>11,207</u>	<u>-229</u>	<u>11,232</u>	<u>-204</u>
<u>Account 904 - Uncollectible Accts.</u>								
16	Non-labor	1,292	-140	1,152	1,183	31	1,292	140
17	TOTAL	<u>1,292</u>	<u>-140</u>	<u>1,152</u>	<u>1,183</u>	<u>31</u>	<u>1,292</u>	<u>140</u>
<u>Total Customer Accounts</u>								
18	Labor	6,844	0	6,844	6,615	-229	6,640	-204
19	Non-labor	<u>5,884</u>	<u>-140</u>	<u>5,744</u>	<u>5,775</u>	<u>31</u>	<u>5,884</u>	<u>140</u>
20	TOTAL	<u>12,728</u>	<u>-140</u>	<u>12,588</u>	<u>12,390</u>	<u>-198</u>	<u>12,524</u>	<u>-64</u>

Source:

Column (A): HECO-901, Page 2. See also HECO response to CA-IR-680, Page 3 for HECO-901, Page 2 Updated for 2004 recorded results.

Col. (D) Exhibit CA-101, Schedule C, Page 1 of 5, Lines 8 and 9.

Col. (F) Exhibit DOD-104, Page 1, Lines 10 and 11.

**HAWAIIAN ELECTRIC COMPANY, INC.**

CUSTOMER DEPOSITS

(ACCOUNT 235.00)

(\$ THOUSANDS)

Line

1	Recorded Balance 12/31/99	3,008
2	Recorded Net Increase in 2000	659
3	Recorded Balance 12/31/00	3,667
4	Recorded Net Increase in 2001	516
5	Recorded Balance 12/31/01	4,183
6	Recorded Net Increase in 2002	300
7	Recorded Balance 12/31/02	4,483
8	Recorded Net Increase in 2003	589
9	Recorded Balance 12/31/03	5,072
10	Recorded Net Decrease in 2004	-6
11	Recorded Balance 12/31/04	5,066
12	Estimated Net Increase in 2005	1,669
13	Estimated Balance 12/31/05	<u>6,735</u>
	Recorded Balance 12/31/04	5,066
	Estimated Balance 12/31/05	<u>6,735</u>
		<u>11,801 /2</u>
	Customer Deposits (simple average)	<u>5,901</u>

Source:  
See HECO-WP-902

HAWAIIAN ELECTRIC COMPANY, INC.

UNCOLLECTIBLE ACCOUNTS EXPENSE

2005

ACCOUNT 904

(\$ THOUSANDS)

<u>Line</u>		<u>Estimated Test Year Revenue</u>
		<u>2005</u>
1	Electric Sales Revenue at Present Rates	\$1,218,267
2	Times Uncollectible Factor	<u>0.0946%</u>
3	Equals Uncollectible Accounts Expense	<u>\$1,152</u>
4	Electric Sales Revenue at Proposed Rates	\$1,280,575
5	Times Uncollectible Factor	<u>0.0946%</u>
6	Equals Uncollectible Accounts Expense	<u>\$1,211</u>

Source:  
Lines 1 & 4: HECO-R-2301

HAWAIIAN ELECTRIC COMPANY, INC  
REBUTTAL 2005 TEST YEAR

CUSTOMER ACCOUNTS EXPENSE  
Summary of HECO and CA Differences to HECO Direct Testimony  
(\$ Thousands)

	(A)	(B)	(C)
	HECO	CA	HECO - CA
	<u>REBUTTAL</u>	<u>TESTIMONY</u>	<u>DIFFERENCE</u>
1     Uncollectible Expense	\$     (140)	\$     (109)	\$         31
2     Standard labor rates and overtime pay	\$         -	\$         (25)	\$         (25)
3     Average employee levels	\$         -	\$         (204)	\$         (204)
	<u>\$     (140)</u>	<u>\$     (338)</u>	<u>\$     (198)</u>

Source:

Column A, Line 1: HECO-R-901, Page 1. (*uncollectible*)

Column B, Line 1: Exhibit CA-101, Schedule C, Page 3, Adjustment C-13, Column (F), Line 9.

Column B, Lines 2 & 3: Exhibit CA-101, Schedule C, Page 4, Line 8, Column (E)

Adjustment C-20 & Column (F) Adjustment C-21.

HAWAIIAN ELECTRIC COMPANY, INC  
REBUTTAL 2005 TEST YEAR

CUSTOMER ACCOUNTS EXPENSE  
Summary of HECO and DOD Differences to HECO Direct Testimony  
(\$ Thousands)

	(A)	(B)	(C)
	<u>HECO</u> <u>REBUTTAL</u>	<u>DOD</u> <u>TESTIMONY</u>	<u>HECO - DOD</u> <u>DIFFERENCE</u>
1     Uncollectible Expense	\$     (140)	\$       -	\$       140
2     Average employee levels	\$       -	\$     (204)	\$     (204)
	<u>\$     (140)</u>	<u>\$     (204)</u>	<u>\$       (64)</u>

Source:

Column A, Line 1: HECO-R-901, Page 1. (*uncollectible*)

Column B, Line 1: Exhibit DOD-104, Page 1, DOD Adjustments Column (B), Line 11.

Column B, Line 2: Exhibit DOD-104, Page 1, DOD Adjustments Column (B), Line 10.

REBUTTAL TESTIMONY OF  
ALAN K.C. HEE

MANAGER  
ENERGY SERVICES DEPARTMENT  
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Customer Service Expense,  
Demand-Side Management Program Expense,  
Energy Cost Adjustment Clause,  
Integrated Resource Planning Expense

INTRODUCTION

Q. Please state your name and business address.

A. My name is Alan K.C. Hee and my business address is 220 South King Street, Honolulu, Hawaii.

Q. What is your position?

A. I am the Manager of Hawaiian Electric Company, Inc.'s ("HECO" or the "Company") Energy Services Department ("ESD").

Q. What is your area of responsibility in this proceeding?

A. My testimony in RT-10 will cover HECO's 2005 test year estimate of Customer Service Expense (including Demand-Side Management ("DSM") expenses), the Energy Cost Adjustment Clause ("ECAC") and incremental Integrated Resource Planning ("IRP") Expense.

CUSTOMER SERVICE EXPENSE

Q. What is HECO's revised 2005 test year estimate for Customer Service Expense?

A. HECO's revised 2005 test year for Customer Service Expense is \$5,284,000, which is \$28,174,000 lower than the estimate in direct testimony, as shown in HECO-R-1001.

Q. What are the reasons for the lower estimate?

A. The lower estimate is due to the net effect of the:

- 1) Removal of incremental DSM expenses as ordered by the Commission in Decision and Order ("D&O") No. 21698, dated March 16, 2005, which also created the Energy Efficiency Docket (Docket No. 05-0069),
- 2) Elimination of the Green Pricing Program and associated expenses,
- 3) Addition of Customer Solutions reorganization expense, and

1           4)    Addition of informational advertising costs for a general education and  
2                   energy awareness program.

3           The impact of these adjustments is shown in HECO-R-1002.

4  
5           Demand-Side Management Expenses

6           Q.    What is the amount of DSM expense removed from Customer Services Expense?

7           A.    The amount of DSM expense removed is \$29,223,000, as shown in HECO-R-  
8                   1003.

9           Q.    Why is this expense being removed from the rate case?

10          A.    In D&O No. 21698, the Commission bifurcated the rate case and separated the  
11                DSM programs into the Energy Efficiency Docket. The \$29,223,000 represents  
12                test year DSM expenses that are not currently being recovered through base rates  
13                less the DSM expenses that the Commission ordered HECO to include in its base  
14                rate request in the next rate case (i.e. this Docket). The amount of DSM expense  
15                remaining in the rate case is \$1,030,000, as shown on line 15 of HECO-R-1003.

16          Q.    How does this amount compare to the expenses identified for removal by HECO  
17                in its response to CA-IR-533, page 8 of 22?

18          A.    The amount of DSM expense being removed from the rate case is \$4,000 more  
19                than the \$29,219,000 identified in CA-IR-533. The slight difference is due to the  
20                use of expense estimates in the Company's test year operating budget rather than  
21                the Company's 2004 DSM Modification and Evaluation ("M&E") Report as the  
22                basis for the test year estimate.

23          Q.    Why did HECO not remove all of the DSM expenses from the rate case?

24          A.    D&O No. 21698 stated that "HECO may temporarily continue, in the manner  
25                currently employed, its existing two (2) residential DSM programs . . . and three

1 (3) C&I DSM programs . . .”. HECO currently recovers DSM program base  
2 labor costs through base rates and incremental DSM program costs through the  
3 DSM component of the IRP clause. Therefore, for the purposes of the rate case  
4 HECO has continued recover the DSM program base labor costs in the manner  
5 currently employed, which is through base rates. The portion of DSM program  
6 costs in base rates represents the base labor expense for HECO employees  
7 involved in DSM program implementation that are already in base rates, plus the  
8 direct labor and certain non-labor costs associated with its two load management  
9 programs that the Commission ordered be included in base rates in the next  
10 (instant) rate case. The total amount of DSM program expenses included in base  
11 rates is \$1,030,000 (as shown in HECO-R-1003, line 15), of which \$1,016,000 is  
12 in Customer Service Expense, as shown in HECO-R-1003, line 17.

13 Q. What is the reason for the difference between the amounts of test year DSM  
14 Expense included in the rate case and the test year DSM expense estimate  
15 included in Customer Service Expense?

16 A. The difference of \$14,000 is primarily base labor expense charged to DSM  
17 expenses from areas outside of the Customer Service block of accounts, which are  
18 included in the test year expense estimate for Administration and General  
19 (“A&G”) Expenses, Accounts 920 and 921. An example is base labor hours  
20 charged by the Regulatory Affairs Division for work on DSM-related filings. Ms.  
21 Sekimura discusses A&G expenses in HECO RT-16.

22 Q. Is the amount of labor expense for base HECO employees already in base rates the  
23 same amount as indicated in CA-IR-533?

24 A. No it is not. The amount of labor expense identified in CA-IR-533, page 9 of 22,  
25 for base HECO employees involved in DSM program implementation was

1           \$340,700. However, that estimate has been decreased slightly to \$337,400  
2           (including the \$14,000 of A&G expense) to match the estimate included in  
3           HECO's test year operating budget.

4       Q.   What do D&O Nos. 21415 and 21421, which approved HECO's Residential  
5           Direct Load Control ("RDLC") and Commercial and Industrial Direct Load  
6           Control ("CIDLC") Programs state with respect to the recovery of load  
7           management program costs?

8       A.   In D&O No. 21415, (Docket No. 03-0166, the RDLC Program) the Commission  
9           approved the Company's and CA's stipulation in its entirety. In the stipulation,  
10          the CA and HECO agreed that:

11                "HECO will not seek to recover the following RDLC Program operation  
12                and maintenance costs through the IRP Cost Recovery Provision: (1) Direct  
13                Labor . . . (2) Advertising/Marketing . . . (3) Training; and (4) Materials and

---

14                Miscellaneous. Instead, the Parties agreed to allow HECO to seek the  
15                recovery of these operation and maintenance costs in base rates in HECO's  
16                next rate case."

17                Similarly, in D&O No. 21421 (Docket No. 03-0415, the CIDLC Program)  
18           the Commission also approved the Company's and CA's stipulation in its entirety.  
19           In the stipulation, the CA and HECO agreed that:

20                "HECO will not seek to recover the following CIDLC Program operation  
21                and maintenance costs through the IRP Cost Recovery Provision: (1) Direct  
22                Labor . . . (2) Materials, Travel, and Miscellaneous. Instead, the Parties  
23                agreed to allow HECO to seek the recovery of these operation and  
24                maintenance costs in base rates in HECO's next rate case."

25                Furthermore, the Commission explicitly stated in D&O No. 21698 (Energy  
26           Efficiency Docket) that "This Order is not intended to nullify the decisions  
27           rendered by the commission in the dockets approving the RDLC and CIDLC

1 Q. What is the amount of test year load management program costs included in base  
2 rates?

3 A. The test year expense estimate for load management program costs included in  
4 base rates is \$692,400, as shown in HECO-R-1004. This is the sum of certain  
5 costs for the RDLC and CIDLC Programs.

6 Q. What is the basis for this estimate of load management program costs?

1 installations for 2005.

Furthermore, while direct mail may work the first time through the residential customer base, subsequent rounds of direct mail pieces to the same customer base will be less effective as customers approached in following years.

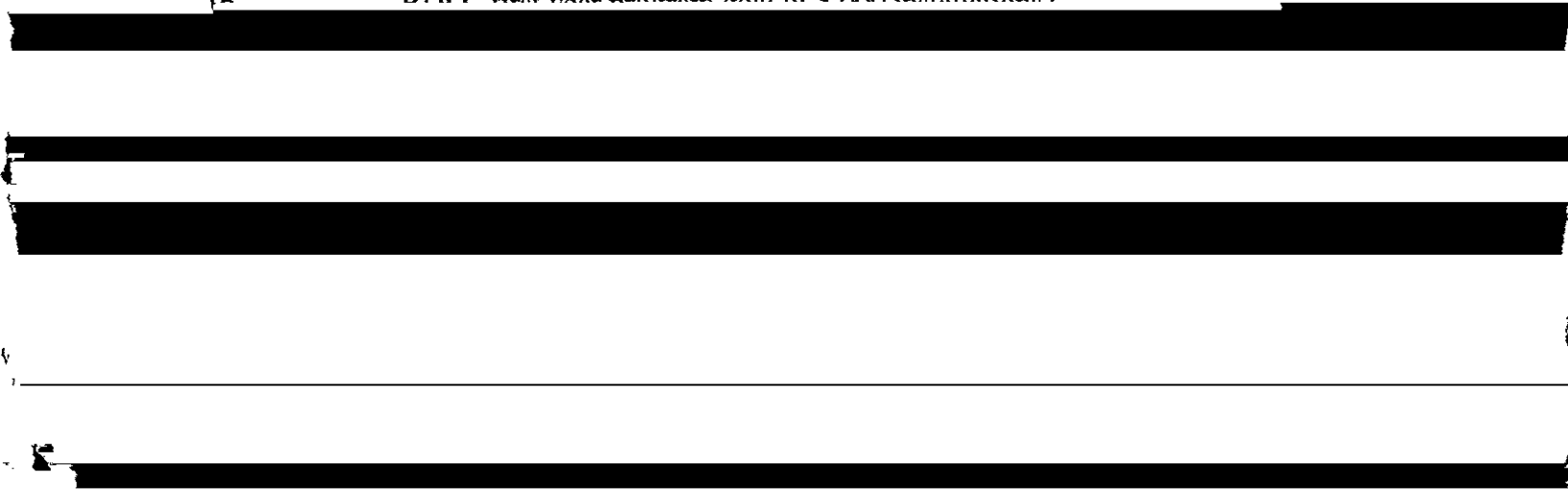
5 will be those that were unwilling or unable to participate during the first year. In  
6 addition, the program application target for RDLC participants will increase from  
7 5,000 installations in 2005 to 7,500 installations in both 2006 and 2007. Thus, as

1 minds or fail eligibility requirements is about 20%. Therefore, the 11,520  
2 appointments would result in 9,200 installations in the first year at \$27 per  
3 installation. The direct mail campaign would need to continue, but at a slower  
4 pace than a direct mail campaign alone since the telemarketing effort would result  
5 in a higher program participation rate per direct mailing.

6 Q. How does the cost of telemarketing compare with the direct mail campaign by  
7 itself?

8 A. The combined direct mail/telemarketing campaign is estimated to cost \$300,000  
9 annually and achieve a program participation of 9,200 installations during the first  
10 year. Therefore, the advertising cost per installation is expected to be about \$33.  
11 The initial cost of a direct mail campaign is about \$22 to \$24 per installation.  
12 However, the direct mail campaign will not achieve the long-term RDLC Program  
13 load reduction goals because the response rate for the direct mail campaign will  
14 drop off rapidly as successive rounds through the customer base are conducted.

15 Q. Why is it necessary to accelerate the number of annual installations beyond the  
16 RDLC first year program goal of 5,000 installations?



1       A.   A 100-hour pilot telemarketing effort began during the week of July 25 in the  
2       Pearl City area following the distribution of the direct mail pieces to the area a  
3       week earlier. The purpose of the pilot is to test the telemarketing script, gauge  
4       customer response, and determine what increase, if any, the effort has on the  
5       number of appointments made over the direct mail approach alone. As of the  
6       filing of this testimony, the results of the telemarketing effort were not available.  
7       However, the Company expects that the pilot will be successful and expects to  
8       immediately begin working with a telemarketing firm to begin full-scale  
9       telemarketing as described above.

10      Q.   Is HECO proposing any other additions to the test year RDLC advertising expense  
11      estimate?

12      A.   Yes. HECO proposes to add an additional \$25,000 for a customer recognition  
13      program. Under the RDLC Program, customer may leave the program at any time  
14      without penalty. This additional cost of \$25,000 is intended to periodically  
15      reinforce the customers' decision to remain in the program through print and other  
16      media, thus avoiding the more expensive cost of acquiring a new participant.  
17      Therefore, HECO proposes to increase the RDLC marketing and advertising  
18      budget by \$275,000 over the estimate included in direct testimony to accelerate  
19      the acquisition of load reductions and maintain system reliability.

20      Q.   Please describe the increase over the approved marketing and advertising program  
21      budget for the CIDLC Program.

22      A.   The approved CIDLC program budget did not include any marketing and  
23      advertising costs. However, CIDLC program participants once enrolled must also  
24      be retained. The CIDLC Program advertising component will recognize  
25      commercial and industrial participants in print and radio, provide materials for

1 display in their offices and/or storefronts identifying them as CIDLC Program  
2 participants, and pursue any other advertising focused on reinforcing participation  
3 and/or recognizing participants. The major purposes of the advertising are to (1)  
4 publicly recognize the contributions that participants are making to maintaining  
5 electrical system reliability for everyone, and (2) assure residential customers that  
6 the commercial and industrial sector is also contributing to demand reductions.  
7 Therefore, HECO has included \$25,000 of CIDLC Program marketing and  
8 advertising expense in base rates.

9  
10 Green Pricing Program

11 Q. What is HECO's revised test year estimate for the Green Pricing Program?

12 A. HECO is eliminating the Green Pricing Program, and has reduced Customer  
13 Service Expense by \$100,000, as shown in HECO-R-1005.

14 Q. Why is HECO eliminating the Green Pricing Program expense?

15 A. HECO has decided that the Green Pricing Program, while important as an element  
16 of its renewable energy strategy, has a lower priority than other initiatives it is  
17 pursuing.

18  
19 Customer Solutions Reorganization

20 Q. What adjustment did HECO make for the Customer Solutions Reorganization?

21 A. HECO increased the test year Customer Services Expense estimate by \$398,600,  
22 as shown in HECO-R-1005. HECO previously provided an estimate of this  
23 impact of the Customer solutions Reorganization on the test year Customer  
24 Services Expense estimate in CA-IR-78.

1 CA-IR-78?

2 A. No it is not. The estimate of \$504,700 provided in CA-IR-78 included both  
3 Account 910 Customer Service and Account 920 A&G expenses. After the  
4 Account 920 expenses are transferred to A&G expense, the revised reorganization  
5 expense for Customer Service account is \$398,600. The transferred A&G  
6 expenses are discussed by Ms. Sekimura in RT-16.

7

8 Informational Advertising

9 Q. What adjustment did HECO make to informational advertising expense?

10 A. HECO increased the test year non-labor Informational Advertising expense by  
11 \$750,000, as shown in HECO-R-1002, from \$321,000 to \$1,071,000. This  
12 increase in the test year Information Advertising expense was previously provided  
13 in CA-IR-533.

14 Q. What is the reason for the increase?

15 A. As described in CA-IR-533, HECO intends to enhance the Company's ability to  
16 educate and inform its customers about ways that they can save energy and reduce  
17 their peak demands. The Company plans to pursue a three-layered conservation  
18 and energy efficiency message. The first message revolves around the importance  
19 of using energy wisely at all times; the second emphasizes that it makes special  
20 sense to reduce energy use at peak; and the third creates a basis for dramatically  
21 cutting the use of electricity during an emergency. In order to deliver these  
22 messages to its customers, HECO intends to procure an expanded presence in  
23 print and broadcast media (including television and radio), as shown in HECO-R-  
24 1006.

25 Q. Is the advertising campaign a DSM program?

1 A. No it is not. This advertising campaign is an education campaign whose purpose  
2 is to establish a foundation of awareness so that customers will be able to  
3 understand why using energy wisely at all times, during the peak, and during an  
4 emergency, is important. The campaign is not claiming that it will achieve a level  
5 of energy or demand savings; therefore, it is not a DSM program.

6 Q. Will DSM Programs be identified in the advertising campaign?

7 A. Yes they will. Since the overall objective of an energy efficiency message is to  
8 encourage customers to conserve energy, it is logical that in the same message  
9 they also be provided actions they can take to reduce energy use. Those actions  
10 include some behaviors that are not encompassed within the Company's DSM  
11 programs (e.g. using fans instead of air-conditioners) and some behaviors that are  
12 related to the Company's DSM programs (e.g. purchasing a solar water heater).  
13 While participation in HECO's DSM Programs will be identified as one of several  
14 actions that customers can take to save energy, the details about the DSM  
15 programs will continue to be provided under HECO's separate DSM Program  
16 advertising budgets.

17 Q. Has the Company made any other revisions to its labor expense estimates?

18 A. Adjustments to the Company's labor-related expenses (including Customer  
19 Service labor expenses) are being reflected in a single adjustment that is further  
20 discussed in HECO RT-16.

21 Q. What is the Company's rebuttal test year estimate for Customer Service Expense?

22 A. HECO's rebuttal test year estimate is \$5,284,000, as shown in HECO-R-1007.

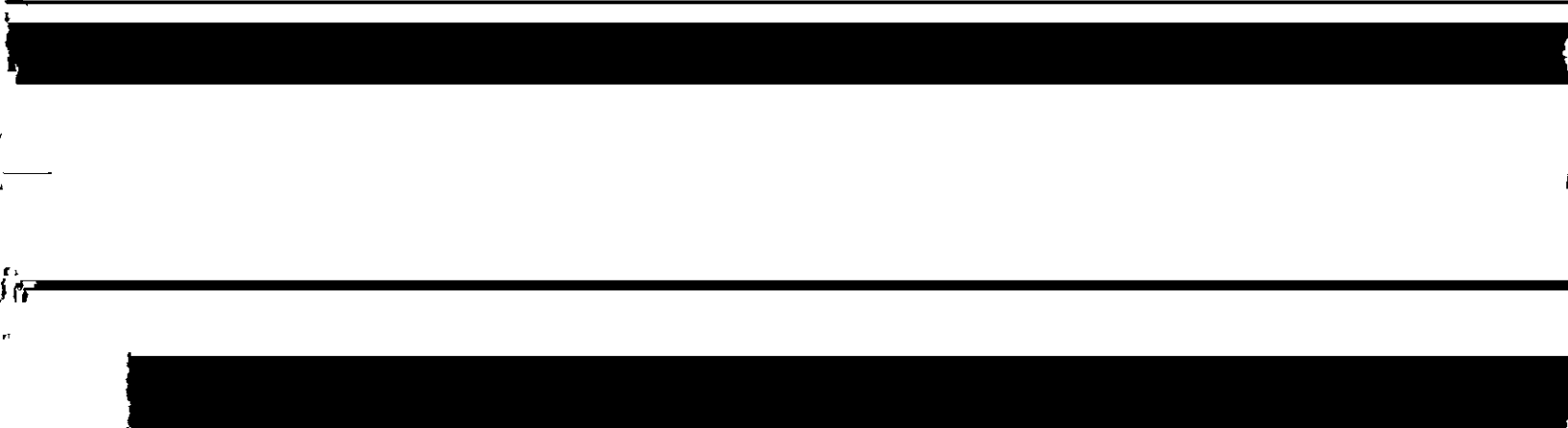
23

24 Estimated Revenues collected through the IRP Clause

25 Q. Mr. Bonnet, HECO RT-23, identifies the estimated revenues from the existing

1           IRP Clause that are used to determine the results of operations at current effective  
2           rates. How were those revenues calculated?

3       A.   The revenues included in HECO-R-2303 represent the estimated lost margins that  
4           result from HECO's existing DSM programs from the time of initial program  
5           implementation in 1996 through 2005. HECO's existing DSM programs are the  
6           Residential Efficient Water Heating, Residential New Construction, Commercial  
7           and Industrial ("C&I") Energy Efficiency, C&I New Construction, and C&I  
8           Custom Rebate Programs. The two existing two load management programs  
9           (Residential Direct Load Control and C&I Direct Load Control Programs) do not  
10          result in lost margins for the purpose of revenue recovery.



- 1           1)    On the estimate of Account 912 Non-labor expense of \$21,000, and
- 2           2)    On the expenses associated with the Customer Solutions Reorganization that
- 3                were presented in CA-IR-78.

4       Q.   Where in testimony do the CA and DOD agree with HECO on the Account 912  
5           non-labor expense?

6       A.   None of the adjustments shown in the CA's Schedule C or in the DOD's exhibit  
7           DOD-114 adjust HECO's test year estimate of Account 912 non-labor expense.  
8           Therefore, neither the CA nor DOD disagreed with the Company's expense  
9           estimate.

10      Q.   How can the CA and DOD agree with HECO on the labor expense associated with  
11           the Customer Solutions Reorganization if the parties' estimates of its impact are  
12           different, as shown in HECO-R-1008 and 1009?

13      A.   Both the CA and DOD accepted HECO's \$504,700 labor expense estimate of the  
14           impact of the Customer Solutions Reorganization that was included in CA-IR-78.  
15           Some portions of the estimate described in CA-IR-78 belong in Customer Service  
16           Expense while the remaining portion belongs in A&G expense. The Company's  
17           rebuttal expense estimate separates these two costs, which lowers the impact on  
18           Customer Services Expense to \$398,600. The derivation of the revised estimate is  
19           shown in HECO-RWP-1005. Ms. Sekimura, in HECO RT-16, discusses the  
20           portion of reorganization expense that is in A&G expense.

21      Q.   In what areas do the parties disagree?

22      A.   The parties disagree on the following areas of Customer Service Expense:

- 23           1)    Account 910, Customer Assistance Expense
- 24           2)    Account 911, Informational Advertising, non-labor expense, and
- 25           3)    Customer Service labor expense.

1 Q. What is the source of disagreement on Customer Assistance Expense?

2 A. The parties disagree on whether an adjustment is necessary to labor expense for  
3 "open" positions and on the amount of DSM expense to remove from the rate case  
4 due to the Energy Efficiency Docket.

5 Q. What is the disagreement on "open" positions?

6 A. Both the CA and DOD reduce the Company's Customer Service labor expense by  
7 \$272,000 to account for positions that they claim will remain unfilled for a portion  
8 of the test year. Ms. Sekimura in RT-16 discusses how the CA and DOD derive  
9 their proposed adjustments.

10 Q. Is this proposed adjustment accurate?

11 A. No it is not, for the following reasons.

12 1) The status of positions in the Customer Solutions area as of July 31

13 demonstrates that many of the positions that were vacant as of December  
14 31, 2004 have since been filled or are in the process of being filled.

15 2) The CA's and DOD's proposed adjustment reduces labor expenses for 4  
16 "open" DSM positions that the CA and DOD already separated from the rate  
17 case because of the Energy Efficiency Docket. Thus, even if the basis for  
18 the CA's and DOD's proposed adjustment was reasonable (which it is not),  
19 it double counts the reduction for vacant DSM positions and overestimates  
20 the impact on Customer Service Expense.

21 Q. What is the current status of positions in the Customer Solutions area as of July  
22 27?

23 A. As of July 27, 2005, four positions remain unfilled and HECO plans to fill all four  
24 positions by the end of 2005. The four vacant positions are: the CIDLC Program  
25 Manager, the load management program engineer, a Senior Resource Planning

1 Analyst, and a Senior Technical Services Engineer, as shown in HECO-R-1010.

2 Since the beginning of the year the following positions open as of December  
3 2004 have been filled (along with the date of hire) as of July 27, 2005: RDLC  
4 Program Manager (3/7/05), Marketing Services Coordinator (3/17/05), DSM  
5 Clerk (1/3/05), Planning Analyst (1/10/05), and Senior Resource Planning Analyst  
6 (7/11/05). Thus, five of the eight "open" positions identified in DOD/HECO-IR-  
7 8-8 for the Customer Solutions area (listed as the Energy Services/IRP  
8 Department in the IR response) have been filled.

9 Q. How many Customer Solutions process area positions are included in the rebuttal  
10 test year?

11 A. There are 56 Customer Solutions process area positions. The Customer Solutions  
12 process area consists of the Vice President, an Executive Secretary, the Energy  
13 Services Department and the Marketing Services, Forecasts and Research,  
14 Customer Technology Applications, and Integrated Resource Planning Divisions.  
15 In direct testimony the total number of process area positions was 64. CA-IR-78  
16 added four unforecasted positions that were related to the Customer Solutions  
17 reorganization bring the total number of positions to 68. Twelve positions were  
18 subsequently removed from the test year due to the bifurcation of the rate case and  
19 establishment of the Energy Efficiency Docket, as described in CA-IR-510.

20 Q. What are the Company's plans to fill the four vacant positions?

21 A. Management approval to fill the CIDLC Program Manager position has been  
22 received. The position was advertised in the daily newspaper and candidate

---

23 interviews began during the week of August 1.

24 The process of management approval for the load management program  
25 engineer will begin by early September 2005, with a request to the Executive

1           Staffing Committee to fill the position. The process will culminate with filling the  
2           position by the end of the year.

3                   The Senior Resource Planning Analyst position was filled on August 1,  
4           2005.

5                   Management approval to fill the Senior Technical Services Engineer

---

6           position has been received and will also be filled by the end of the year.

7           Q.   How does the CA's and DOD's proposed \$272,000 labor expense adjustment  
8           over-estimate the impact of "open" positions?

9           A.   The proposed adjustment is based on a number of "open" positions, which  
10          includes four DSM related positions that both the CA and DOD had already  
11          separated from the rate case with adjustment C-17 and DOD-116, respectively.  
12          Those adjustments removed all DSM expenses, including labor expenses, from the  
13          rate case. Thus, in effect, the CA and DOD are removing these four positions  
14          twice. The parties recognize the error in their response to HECO/CA-IR-209 and  
15          HECO/DOD-IR-112. To remove the double count, the CA's adjustment for  
16          "open" positions must be reduced by \$124,800, as shown in HECO-R-1011,  
17          resulting in a revised adjustment of \$147,200. Note that HECO does not agree  
18          that an adjustment for "open" positions is reasonable. Please see HECO RT-16.

19          Q.   Are there any employee positions in the Energy Solutions area that were approved  
20          after the 2005 test year forecast of employees was developed?

21          A.   Yes, in the Customer Installations Department ("CID") there are five employee  
22          positions that were approved after the 2005 test year forecast of employees was  
23          developed. As a result, these positions and their wages and benefits are not  
24          included in 2005 test year numbers. Ms. Sekimura in HECO RT-16, shows how a  
25          portion of the wages and benefits will be accounted for in capital, while the

1 remaining portion will increase O&M expense.

2 Q. What are the five positions and why are they needed?

3 A. The five positions in CID are two (2) junior drafters, two (2) Meter Senior  
4 Helpers/Meter Apprentices, and one (1) Operations Analyst.

5 Junior Drafters are needed to fulfill the existing drafting workload of the  
6 CID Planners and Designers, to support the existing joint pole process, and to  
7 support the future drafting requirements for the Energy Solutions process area.  
8 One of these two positions was filled on June 6, 2005. The other position will be  
9 filed in October 2005.

10 The Meter Senior Helpers/Meter Apprentices are needed now that the  
11 Senior Meter Electrician apprenticeship program has been reinstated. The  
12 apprenticeship program will allow CID to have fully qualified Senior Meter  
13 Electricians in approximately three to five years from now. The program was  
14 reinstated because three Meter employees will have the age and years of service to  
15 become eligible to retire within the three to five year training period. The two  
16 Meter Senior Helper/Meter Apprentice positions were filled on January 31, 2005.

17 The Operations Analyst is needed to support SOX administration,  
18 monitoring, and compliance, and management accounting support for various  
19 internal and external processes. Additionally, this position will allow CID to  
20 allocate key resources to the CIS and other major project initiatives involving the  
21 department. The Operations Analyst position was filled on April 11, 2005.

22 Q. What is the disagreement on the amount of DSM expense to remove from the rate  
23 case?

24 A. The Company removed \$29,223,000 in DSM expense leaving \$1,030,000 in the  
25 rate case. Both the CA and DOD removed all DSM expenses.

1 Q. What is the source of the disagreement?

2 A. The disagreement stems from the CA's and DOD's misinterpretation of the  
3 Commission's D&O No. 21698 that created the Energy Efficiency Docket. The  
4 D&O states that "HECO may temporarily continue, in the manner currently  
5 employed," its existing two residential DSM programs and three C&I DSM  
6 programs (emphasis added). Therefore, HECO has continued to include in base  
7 rates (in the manner currently employed) the portion of DSM program costs that  
8 represents the labor expense for HECO employees already included in base rates  
9 that are involved in DSM program implementation.

10 Further, page 13 of the Commission's D&O No. 21698 states that "This  
11 Order is not intended to nullify the decisions rendered by the commission in the  
12 dockets approving the RDLC and CIDLC programs, Docket Nos. 03-0166 and 03-  
13 0415, respectively." As discussed earlier in my testimony, the Commission  
14 approved the Settlement Agreements reached between HECO and the CA in those  
15 dockets in which the parties agreed to allow HECO to seek the recovery of certain  
16 operation and maintenance costs in base rates in HECO's next rate case.

17 Therefore, consistent with D&O No. 21698 and the D&Os issued regarding  
18 HECO's two load management program applications, HECO has included  
19 estimates of those identified expenses in base rates. The total amount of DSM  
20 expenses included in the test year estimate of Customer Assistance Expense, and  
21 the adjustment necessary to HECO's estimate in direct testimony, are shown in  
22 HECO-R-1002.

23 Q. What is the CA's and DOD's interpretation of D&O No. 21698 and why is that  
24 interpretation incorrect?

25 A. Both the CA and DOD interpret D&O No. 21698 to mean that all DSM expenses

1 are to be removed from the rate case. As indicated above, that interpretation is  
2 incorrect because the D&O states that the energy efficiency programs are to  
3 continue in the manner currently employed and the CA itself agreed to allow  
4 HECO to seek recovery of certain load management expense in base rates in its  
5 next rate case. Furthermore, the CA, in its response to HECO/CA-IR-205, part b.  
6 admits that "Decision and Order No. 21698 does not explicitly require the  
7 separation of the DSM program expenses already in base rates and place them into  
8 the Energy Efficiency Docket."

9 Therefore, the CA and DOD have over-estimated the amount of DSM  
10 expense that is to be removed from Customer Assistance Expense by \$1,030,000  
11 and under-estimated the amount of test year Customer Assistance Expense by the  
12 same amount.

13 Q. What then is the basis for the CA's contention that all DSM expenses must be  
14 removed from the rate case?

15 A. In HECO/CA-IR-205, the CA suggests that the Commission's order to  
16 "temporarily continue" the five existing energy efficiency programs "until further  
17 order by the commission" does not provide "sufficient certainty that these  
18 programs will continue as proposed". Further, the CA contends that cost recovery  
19 is one of the issues to be taken up by the Energy Efficiency Docket. The CA  
20 concludes that there is "no assurance that the Commission will approve, for cost  
21 recovery, the amounts that HECO has included in the 2005 test year forecast to  
22 support base rate inclusion at the present time."

23 Q. Does HECO agree with the CA's position?

24 A. No, it does not. The CA's suggestion that the Commission's D&O No. 21698  
25 does not provide "sufficient certainty that these DSM programs will continue"

1 ignores the Commission's explicit statement in a footnote on page 13 of the D&O  
2 that nothing in the order nullifies the Commission's decisions approving the  
3 RDLC and CIDLC programs. The Commission's decisions in those two dockets  
4 means that certain identified costs of the load management programs belong in  
5 base rates.

6 In addition, the Company's understanding of the Commission's order to  
7 temporarily continue, "in the manner currently employed", the existing energy  
8 efficiency programs, is that the manner of current cost recovery should also  
9 continue. The current cost recovery mechanism is to recover costs both through  
10 base rates and the DSM component of the IRP Clause.

11 Q. Are there other areas of disagreement in Customer Assistance Expense?

12 A. Yes. The DOD has not eliminated the Green Pricing Program costs from  
13 Customer Assistance Expense, while both the CA and HECO have eliminated the  
14 cost.

15 Q. What is the source of disagreement on non-labor Informational Advertising  
16 expense?

17 A. HECO is including the costs of a conservation and energy efficiency message to  
18 inform its customers about ways that they can save energy and reduce their peak  
19 demands. This addition of \$750,000 to the advertising budget was identified and  
20 discussed in CA-IR-533. Both the CA and DOD do not agree with the additional  
21 expense. As this is the CA's and DOD's only adjustment to the Company's  
22 Account 911 non-labor expense estimate, the parties agree with the remaining  
23 non-labor expense estimate of \$321,000.

24 Q. Why do the CA and DOD not agree with the additional \$750,000 expense?

25 A. The CA opposes the additional informational advertising expense based on the

HECO RT-10  
DOCKET NO. 04-0113  
PAGE 21 OF 37

1 purpose is to establish a foundation of awareness so that customers will be  
2 able to understand why using energy wisely at all times, during the peak,  
3 and during an emergency is important.

4 Thus, approval of HECO's proposal does not require meeting the cost-  
5 effectiveness criteria set by the IRP Framework, nor should it require  
6 meeting those criteria. The bases for allowing expenses into base rates are  
7 that they are "reasonable" and "prudent". To show that expenses are a cost  
8 effective means of achieving the objectives is not a "fundamental principle  
9 of utility regulation" as the CA would have the Commission believe.

10 The Commission's action concerning HECO's proposed RCEA  
11 program should not predispose the Commission against the Company's  
12 current proposal for an energy awareness campaign. On the contrary, in its  
13 RCEA Program D&O, the Commission stated that,

14 "The commission understands HECO's need and desire to educate its  
15 residential customers about energy matters, including conservation.  
16 We further recognize that educating residential customer to encourage  
17 energy conservations and make them aware of (1) measures that can  
18 be taken during the crucial 5:00 p.m. to 9:00 p.m. priority peak period;  
19 and (2) their impact on the need for future electrical generation may  
20 provide some relief to HEC in reducing peak loads, which ultimately  
21 will assist HECO in maintaining its generating system reliability  
22 guideline."

- 
- 23 2) The CA contends that the late introduction of the awareness campaign  
24 harms its ability to consider and discover the issue. HECO acknowledges  
25 that after responding to over 800 information requests some of its responses  
26 were completed after the due date. However, HECO worked diligently to  
27 develop its awareness campaign proposal once it received the PUC's D&O  
28 in April 2005 and provided details of the proposal as soon as it was

1 available. The procedural schedule for this proceeding does include time for  
2 the CA to request, and for HECO to respond to, rebuttal information  
3 requests wherein the CA may consider and conduct further discovery on this  
4 issue.

5 3) The CA improperly applies the approval criteria for a DSM pilot program to  
6 HECO's proposal for an energy awareness education campaign. The two  
7 proposals are different because a DSM pilot program must identify the  
8 "level of achievement" while expenditures for an energy awareness  
9 campaign must be shown to be "reasonable" and "prudent". HECO has met  
10 the latter criteria, as shown in its response to CA-IR-533.

11 4) The additional expenditures for the energy awareness education campaign  
12 will be on-going because the need to pursue energy and load reduction will  
13 exist at least until the in-service date of the next central station generating  
14 unit scheduled for 2009. Therefore, the energy awareness campaign must  
15 continue to educate and reinforce customer behavior to use energy wisely.

16 Q. What is the remaining difference between HECO and the Consumer Advocate for  
17 Customer Service labor expense?

18 A. The remaining difference of \$14,000 relates to the Standard Labor Rate  
19 Adjustment. As discussed by Ms. Faye Yamauchi in HECO RT-13, HECO, the  
20 Consumer Advocate and the DOD are in agreement with the Standard Labor Rate  
21 Adjustment. HECO is reflecting the adjustment as a separate line item in the  
22 results of operations. The Consumer Advocate attempted to allocate the total  
23 adjustment to each block of accounts, which is the reason for the apparent  
24 difference. (The DOD reflected the entire amount in A&G expenses.) HECO's  
25 Customer Service estimate, if reduced by the amount of the CA's proposed

---

1 allocation of the Standard Labor Rate Adjustment, would be \$5,270,000.

2 Research and Development Costs

3 Q. What issues has the CA raised with respect to the ESA development funds?

4 A. The CA recommended that costs incurred prospectively for ESA development be  
5 deferred as a regulatory asset, net of any royalties or other income received, for  
6 consideration and possible rate recovery in future regulatory proceedings.

7 Q. Did the CA offer another option for the ESA development funds?

8 A. Yes. CA stated that if the Commission disagreed with the CA's proposed deferral  
9 and possible future recovery, an alternative option would be to allow only  
10 \$121,000 (based on HECO anticipated payments in 2005).

11 Q. Does HECO agree with the CA's proposal or option?

12 A. HECO agrees with the CA's option to allow \$121,000 for 2005 ESA  
13 development, but seeks flexibility in the use of the remaining funds in other  
14 research and development ("R&D") projects. HECO's expenditures for R&D  
15 activities could increase in the future so the test year level of expenses might  
16 actually understate the on going level of expenses for this type of activity. In  
17 order to meet the requirements of the current Renewable Portfolio Standards law  
18 and growing customer needs, new types of technologies will have to be explored  
19 and developed.

20 HECO is positioning itself to be even more proactive in the advancement of  
21 other new technologies and assessment of revolving and evolving energy policies.  
22 Only by assessing the next steps and next technologies through research,  
23 development and demonstration (RD&D) can HECO implement new generation

1 include, but would not be limited to, hydrogen energy, fuel cells, advanced energy  
2 storage systems, technology related to utility activities and enhancements to  
3 demand-side management for peak shaving, reliability, etc., long-term planning,  
4 and other emerging technologies. Some of the state and federal energy policies  
5 are renewable portfolio standards, net energy metering, system benefit charges,  
6 protecting the environment, reducing impact on customer rates, energy security,  
7 carbon emissions, energy credit trading, tax credits, and other energy policies.

8 Q. How does HECO plan to spend the remaining ESA funds for R&D projects?

9 A. HECO plans to spend the remaining ESA funds in 2005 for the following projects:

- 10 • Testing and characterization of a 1 kW liquefied petroleum gas ("LPG")  
11 reforming unit designed for residential use,
- 12 • Stationary sodium-sulfur ("NaS") battery energy storage,
- 13 • Performance assessment of emerging photovoltaic ("PV") technology, and
- 14 • Research and development of a new communication technology for advanced  
15 meter and customer outage detection devices.

16 Mr. Fujinaka discusses the first three projects in HECO RT-6.

17 New Communications Technology for Advanced Meter and Customer Outage  
18 Detection Project

19 Q. Can you provide a summary on the research and development of a new  
20 communication technology for advanced meter and customer outage detection  
21 devices?

22 A. To support the strategy to create more customer choices, HECO will work with  
23 engineering manufacturers to develop and demonstrate prototypes of customer  
24 and grid data collection/communication devices.

25 The deliverables for this program include hybrid power line and wireless

1 communications for metering and distribution equipment such as transformers  
2 points, distribution substation remote terminal units (RTU), distribution substation  
3 supervisory control and data acquisition systems (SCADA). With two-way  
4 communications to critical points in the distribution system, HECO will be able to  
5 detect the specific point of equipment failure and the downstream customers  
6 affected by the outage via the meter as the gateway device. When a piece of  
7 equipment fails, the dispatch operation will receive an alarm notification of the  
8 on/off power status of each device. Knowing what specific device has failed and  
9 the location of the device will allow the dispatch operation center to more

10 effectively direct the trouble crew to the specific location to repair and restore the  
11 system.

The program will also demonstrate the integration of prototype two-way communications devices with the existing cellular and radio paging systems. The schedule for this program is broken into three phases as follows; Phase 1 (2005) –

1 customers in the future. Presently we have a manual system for interfacing with  
2 our meters. With the development of new hybrid power line and wireless  
3 communications we will have the capability to provide two-way communications  
4 capability for not only reading meters but also providing time-of-use or real-time  
5 pricing signals to our customers – resulting in a more efficient system for how  
6 energy is used. With this two-way communications system, we will also be able  
7 to better manage the power quality service level that we deliver to each customer  
8 – which is becoming more and more critical in this digital age. Detection of  
9 power quality service at the customer premise via the meter gateway will allow  
10 HECO to do conditioned-based maintenance of its distribution system to limit the  
11 impact of outages to customers. Today, we have limited access to customer  
12 energy profile usage information. In the future, with a ubiquitous two-way  
13 communications system to the meter gateway – we will have the ability to better  
14 understand the customer class level usage information, which will translate to a  
15 more efficient system for delivery energy to the market.

16 Q. Can you provide the cost estimate for this phase of the program?

17 A. This first phase of the program will cost about \$180,000 for calendar year 2005.

18 Q. Does HECO have any signed agreements?

19 A. HECO has been in communications with the technology manufacturer and plans  
20 to sign an agreement soon.

21 Q. What are the future activities for this project?

22 A: Future phases of this program will include further development and demonstration  
23 of meters and distribution capacitors with a focus on bench and field testing of  
24 these devices, commencement of hardware and software protocols development  
25 for integration with existing/future back-office application systems such as office

1 data warehousing and middle-ware integration, customer information service  
2 (“CIS”), outage management system (“OMS”) and energy management system  
3 (“EMS”).  
4

5 ENERGY COST ADJUSTMENT CLAUSE

6 Q. What is HECO’s estimate for the Energy Cost Adjustment (“ECA”) factor at  
7 present and proposed rates?

8 A. HECO’s estimates of the ECA factor at present and proposed rates are 5.414  
9 cents/kwh and 0.000 cents/kwh, respectively, as shown in HECO-R-1012.

10 Q. How does the ECA factor differ from direct testimony?

11 A. The ECA factor at present rates in this rebuttal testimony is higher than the ECA  
12 factor in direct testimony, as shown in HECO-R-1013.

13 Q. Why has the ECA factor at present rates changed from direct testimony?

14 A. The ECA factor at present rates has been updated to reflect test year rebuttal  
15 estimates of fuel consumption, fuel expense, generation output, distributed  
16 generation (“DG”) energy, and purchased power discussed by Mr. Sakuda in  
17 HECO RT-4 and Mr. Ching in HECO RT-5.

18 Q. Is HECO proposing to include a CHP component in the ECA calculations?

19 A. Yes. However, the CHP component has been renamed the “DG” component, to  
20 reflect the installation of DG capacity, rather than CHP, in the test year as  
21 discussed by Mr. Sakuda in HECO RT-4.

22 Q. Is HECO still proposing to set the test year ECA factor at proposed rates to 0.00  
23 cents/kwh?

24 A. Yes, as shown in HECO-R-1013.

25 Q. In what areas do the parties agree?

1 A. The parties agree that:

2 1) The ECA Clause should be continued,

3 2) A DG component should be added to the ECA Clause, and

4 3) The ECA factor at proposed rates should be reset to zero.

5 Q. What are the CA's and DOD's positions on the continuation of the ECA Clause?

6 A. The CA agrees that the ECA Clause should be continued. In CA-T-1, page 35, the  
7 CA states that,

8 "Fuel price volatility in international fuel markets and HECO's dependence  
9 upon such markets makes ECAC continuation important to the Company  
10 and its ability to timely recover fluctuating costs thereby minimizing  
11 earnings volatility and the risk of reduced access to capital markets on  
12 reasonable terms."

13 The DOD does not explicitly state a position on the continuation of the ECA  
14 Clause but bases its derivation of ECA Revenues on the CA's estimates, as shown  
15 in DOD-126.

16 Q. What are the CA's and DOD's positions on inclusion of a DG Component in the  
17 ECA Clause?

18 A. The CA agrees with the DG Component, as indicated by its use of the DG  
19 Component in its ECAF calculations in CA-314, page 1. The DOD based its  
20 derivation of the ECAF on the CA's estimates.

21 Q. Do the CA and DOD also reset the ECAF at proposed rates to zero?

22 A. The CA does not show the ECAF at proposed rates. However, in CA-314,  
23 Determination of Base Fuel Energy Charge at Proposed Rates, the CA clearly  
24 intends to embed the Generation, DG, and Purchased Energy cost components  
25 into base rates. which results in an ECAF at proposed rates being zero.

---

26 The DOD also does not show the ECAF at proposed rates. However, it

1 based its estimate of the ECAF on the CA's calculations.

2 Q. In what areas of the ECA Clause do the parties disagree?

3 A. The parties disagree over the ECAF at present rates.

4 Q. How does the Company's estimate for the test year ECA factor at present rates  
5 compare to the CA's estimate?

6 A. As shown in HECO-R-1014, HECO's ECA factor is 0.375 cents/kwh lower than  
7 the CA's estimate.

8 Q. Why are the Company's estimates for the test year ECA factor different from the  
9 CA's estimates?

10 A. HECO's estimated ECA factor is different because it is based on HECO's  
11 estimates of test year fuel expense and fuel consumption, which are different from  
12 the CA's estimates of test year fuel expense and consumption. These differences  
13 are discussed in Mr. Sakuda's and Mr. Ching's rebuttal testimonies.

14 Q. Does the CA agree with the calculation method used by HECO for the ECA  
15 factor?

16 A. Yes, the CA uses the same method of calculating the ECA factor as HECO.

17 Q. What are the test year avoided energy cost payment rates?

18 A. Based on the updated Generation Component and DG Energy Component in the  
19 ECA calculations, the avoided energy cost payment rates are 12.02 cents/kwh (on-  
20 peak) and 9.13 cents/kwh (off-peak), as shown in HECO-R-1015, page 2.

21 Q. In determining the Composite Cost of Total Generation (HECO & DG) in the  
22 calculation of avoided energy cost payment rates and Schedule Q, did HECO  
23 include the DG energy component in its calculations?

24 A. Yes. As shown in HECO-R-1015, page 1, HECO included the weighted Central  
25 Station Energy Component (868.4225 cents/mbtu) and weighted DG Energy

- 1 Component (2.0041 cents/mbtu) in determining the Total Generation Composite
- 2 Cost (Central Station & DG) of 870.43 cents/mbtu.

- 3 Q Does the CA agree with the calculation method used by HECO for the avoided cost?

- 4 energy cost payment rates and Schedule Q?

- 5 A Yes. The CA uses the same method to calculate the avoided energy cost.

1 placeholder, the CA's adjustment to ECAC revenue from the CA's Exhibit CA-  
2 101 Schedule C-4.

3 Q. Did the DOD adjust fuel and purchased power expense that would be used in  
4 determining the ECA factor?

5 A. Yes. The DOD provided as a placeholder the CA's adjustment to Fuel Expense  
6 and Purchase Power Expense from the CA's Exhibit CA-101 Schedule C-4. The  
7 DOD's fuel expense and purchased power are discussed in Mr. Sakuda's and Mr.  
8 Ching's rebuttal testimonies.

9 Q. Did the DOD properly adjust fuel expense that would be used in the calculation of  
10 the ECA factor?

11 A. No. Besides the CA's adjustment to fuel expense, the DOD double counted by  
12 subtracting the fuel expense for utility owned CHP in the amount of \$838,000  
13 which was already in the CA's adjustment. In the DOD's response to  
14 HECO/DOD-IR-114, they agreed that this was a duplicate adjustment.

15

16 SALES HEAT RATE

17 Q. What is the test year sales heat rate that is to be used as the efficiency factor in  
18 HECO's proposed ECA Clause?

19 A. The sales heat rate is 11,140 btu/kwh sales.

20 Q. How does the sales heat rate differ from direct testimony?

21 A. As shown in HECO-R-1016, HECO's rebuttal sales heat rate is higher than the  
22 sales heat rate in direct testimony.

23 Q. Why did the sales heat rate change from direct testimony?

24 A. The sales heat rate has been updated to reflect updated estimates of fuel  
25 consumption and the percentage of central station generation contribution to net

1 system input, as discussed in Mr. Sakuda's rebuttal testimony.

2 Q. How does the CA's estimated sales heat rate compare to the Company's test year  
3 estimate?

4 A. As shown in HECO-R-1017, HECO's sales heat rate is 68 btu/kwh sales higher  
5 than the CA's estimate.

6 Q. Why is the CA's estimated sales heat rate different from the Company's test year  
7 estimate?

8 A. The CA's and HECO's estimated sales heat rates are different because the CA's  
9 estimated test year fuel consumption and percentage of central station generation  
10 contribution to net system input are different from HECO's estimates. These  
11 differences are discussed Mr. Sakuda's rebuttal testimony.

12 Q. Does the CA agree with the calculation used by HECO in determining the sales  
13 heat rate?

14 A. Yes, the CA uses the same method of calculating the sales heat rate as HECO.  
15

16 INTEGRATED RESOURCE PLANNING

17 Q. What is HECO's position on recovery of IRP expense?

18 A. HECO's position is that all IRP general planning costs should be recovered  
19 through base rates including the \$685,000 currently recovered through base rates  
20 and the \$618,000 of normalized incremental IRP general planning cost that HECO  
21 proposes to recover through base rates.

22 Q. What is the CA's position on recovery of IRP expense?

23 A. The CA has stated its concurrence with base rate inclusion of \$685,000 currently  
24 recovered through base rates (CA-T-2, p. 60 at 13 – 14 and CA response to  
25 HECO/CA-IR-208). The CA has also stated that \$618,000 of normalized

1 incremental IRP general planning cost should be removed from the amount  
2 HECO proposes to recover through base rates (CA-T-2, p. 56 at 17 – 19). The  
3 CA states that it has not quantified a normalized incremental IRP general  
4 planning cost and that the issue of the recovery of incremental IRP general  
5 planning costs can be considered in the Energy Efficiency Docket (CA response  
6 to HECO/CA-IR-208a).

7 Q. Why does the CA recommend removing the normalized incremental IRP general  
8 planning cost from the amount HECO proposes to recover from base rates?

9 A. The CA indicates that the amount for the two forecast years, 2004 and 2005, are  
10 significantly higher than the 2003 actual amount. The CA also indicates the actual

---

11 2003 actual amount is significantly higher than HECO's proposed incremental  
12 amounts associated with calendar years 1998 – 2002, which have been disputed  
13 by the CA (CA response to HECO/CA-IR-208).

14 Q. Why is HECO's proposed normalized incremental IRP general planning cost  
15 higher than 2003 and prior years actual cost?

16 A. The incremental IRP general planning cost is associated primarily with the  
17 preparation of the IRP plan. The last IRP plan was filed in January 1998. HECO  
18 began preparing its next cycle of IRP in July of 2003, thus the actual incremental  
19 cost for 2003 is significantly higher than the actual incremental IRP cost for 1998  
20 – 2002. HECO expended significant effort in its current cycle of IRP throughout  
21 2004 and is expected to continue that effort throughout 2005; thus, the forecasts  
22 for 2004 and 2005 are significantly higher than the actual incremental IRP cost  
23 incurred in 2003.

24 Q. What has been HECO's actual incremental IRP general planning cost since HECO  
25 prepared its previous IRP in 1998?

1       A.   HECO R-1018 shows HECO's actual incremental IRP general planning cost from  
2       1995 to 2004. As can be seen from the exhibit, the incremental IRP general  
3       planning costs were at a high level in the years prior to HECO filing its previous  
4       IRP in 1998. This reflects the level of effort necessary to develop the IRP plan.  
5       After the IRP was filed, the level of IRP activities was lower and reflects on-going  
6       activities including regulatory proceedings. In 2000 and 2001, the incremental  
7       IRP general planning cost were low as there was less IRP activity until the  
8       Commission issued its Decision and Order in 2001. Actual incremental IRP  
9       general planning costs again increased in 2003 and 2004 as HECO began efforts  
10      to prepare its next IRP plan.

11      Q.   Why is it reasonable to use incremental IRP general planning costs for 2003  
12      through 2005 to normalize the incremental IRP general planning cost?

13      A.   The Company's methodology for derivation of the normalization amount is  
14      reasonable because it is consistent with D&O No. 18365 (Docket No. 99-0207,  
15      HELCO's test year 2000 rate case). In D&O No. 18365, HELCO's IRP cost to be  
16      included in base rates was derived using an average of 3 years (1997 – 1999). In  
17      addition, it would not be appropriate to use actual costs from 2000 through 2002  
18      as the level of IRP activity was unusually low during these years preceding the  
19      Decision and Order in the docket.

20      Q.   Is it typical for the incremental IRP general planning cost to fluctuate from year to  
21      year?

22      A.   Yes. For the reasons I just explained, the level of IRP activities has fluctuated

23      monthly from year to year and thus the incremental IRP cost has fluctuated.

1 Q. What was the outcome in the most recent HELCO rate case regarding incremental  
2 IRP general planning cost?

3 A. In HELCO's last rate case the Commission stated that it is appropriate for  
4 HELCO to recover its incremental IRP costs through base rates (Decision and  
5 Order No. 18365 dated February 8, 2001, Docket No. 99-0207, page 20) even  
6 though HELCO testified that incremental IRP general planning cost is volatile.

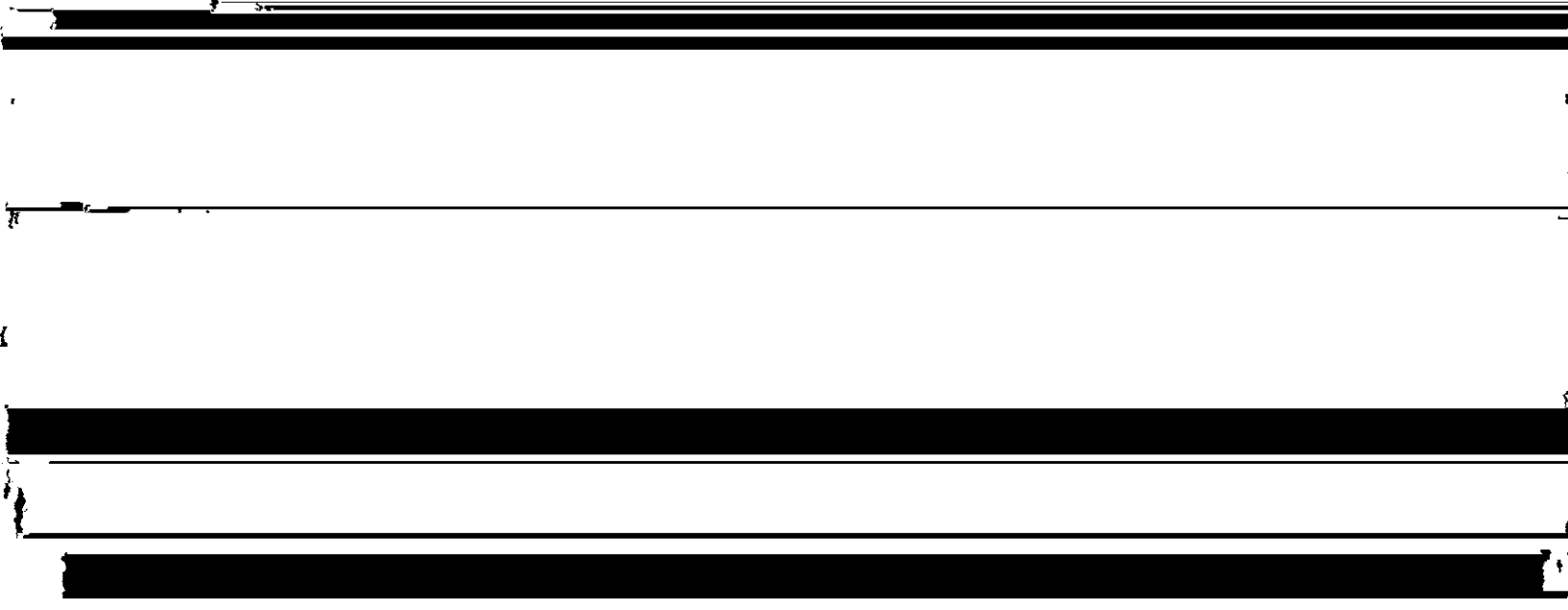
7 Q. The CA contended that the issue of incremental IRP general planning cost can be  
8 addressed in the Energy Efficiency Docket. Is it appropriate to address the  
9 recovery of IRP expenses in the Energy Efficiency Docket?

10 A. No. It is not appropriate to address incremental IRP general planning cost in the  
11 Energy Efficiency Docket as that docket was established to address issues  
12 surrounding energy efficiency subjects and not IRP expenses. Rather, it is  
13 appropriate to address the issue of incremental IRP general planning cost in the  
14 HELCO rate case as there is sufficient certainty that the IRP process will continue  
15 to be conducted in the future and that the costs will be incurred.

1       A.    The DOD has stated its concurrence with base rate inclusion of \$685,000  
2           currently recovered through base rates. The DOD has also stated that \$618,000 of  
3           normalized incremental IRP general planning cost should be removed from the  
4           amount HECO proposes to recover through base rates. The DOD states that the  
5           \$618,000 of incremental costs should be removed because they were identified as  
6           being "incremental" (i.e. increased costs) and should therefore be addressed in the  
7           Energy Efficiency Docket (DOD response to HECO/DOD-IR-110 part b.).

8       Q.    Should the incremental IRP general planning cost be addressed in the Energy  
9           Efficiency Docket?

10      A.    No. The DOD's rationale that incremental IRP general planning cost should be  
11           moved to the Energy Efficiency Docket because it reflects an increase in cost is  
12           not persuasive. As stated above, the Energy Efficiency Docket was established to  
13           address issues surrounding the demand-side management programs and not IRP  
14           expenses. Whether the proposed incremental IRP general planning cost



HAWAIIAN ELECTRIC COMPANY, INC.  
**CUSTOMER SERVICE EXPENSE**  
REBUTTAL TEST YEAR 2005 (\$1000)

	<u>DIRECT</u>	<u>BUD ADJ</u>	<u>REBUTTAL</u>
<b>CUSTOMER SVC EXPENSE</b>			
909 SUPERVISION			
LABOR	31		31
NON-LABOR	0		0
TOTAL 909	<u>31</u>	<u>0</u>	<u>31</u>
910 CUSTOMER ASSISTANCE EXP			
LABOR	3,662	(448)	3,214
NON-LABOR	29,400	(28,476)	924
TOTAL 910	<u>33,062</u>	<u>(28,924)</u>	<u>4,138</u>
911 INFORMATIONAL ADVERTISING EXP			
LABOR	10		10
NON-LABOR	321	750	1,071
TOTAL 911	<u>331</u>	<u>750</u>	<u>1,081</u>
912 MISC CUSTOMER SERVICE EXPENSES			
LABOR	13		13
NON-LABOR	21		21
TOTAL 912	<u>34</u>	<u>0</u>	<u>34</u>
CUSTOMER SERVICE - TOTAL			
LABOR	3,716	(448)	3,268
NON-LABOR	29,742	(27,726)	2,016
TOTAL	<u>33,458</u>	<u>(28,174)</u>	<u>5,284</u>

Reference: HECO-RWP-1001

HAWAIIAN ELECTRIC COMPANY, INC.

CUSTOMER SERVICE EXPENSE

REBUTTAL 2005 TEST YEAR

(\$1000s)

A	B	C	D	E	F	G	H
Customer Service Expense							
		Direct 2005	Remove DSM	Remove Green Prc	Add Cust Sol Reorg	Add Engy Awareness	Rebuttal 2005
1	909	Supervision	31				31
2	910	Customer Assistance	33,062	-29,223	-100	399	4,138
3	911	Informational Advertising	331			750	1,081
4	912	Miscellaneous Customer Service	34				34
5	TOTAL		33,458	-29,223	-100	399	5,284

Col C: HECO-1001  
Col D: HECO-R-1003  
Col E: HECO-R-1005  
Col F: HECO-R-1005  
Col G: CA-IR-533

Hawaiian Electric Company, Inc.

**DSM Program Expense Summary**  
**Account 910**  
**Rebuttal Testimony**

	2005 Test Year <u>Estimate*</u>	<u>Adjustment</u>	Revised 2005 Test Year <u>Estimate**</u>
1 Incentives	10,863,285	-10,863,285	0
Direct Labor			
2 Base	368,074	291,972	660,046
3 Incremental	<u>1,435,317</u>	<u>-1,435,317</u>	<u>0</u>
4 Subtotal	1,803,391	-1,143,345	660,046
Outside Services			
5 Implementation	4,095,770	-4,095,770	0
6 Tracking	35,000	-35,000	0
7 Evaluation	175,501	-175,501	0
8 PEA, Feasibility Studies	<u>425,000</u>	<u>-425,000</u>	<u>0</u>
9 Subtotal	4,731,271	-4,731,271	0
10 Advertising/Marketing	3,221,841	-2,871,841	350,000
11 Material, Travel, Misc.	<u>834,843</u>	<u>-815,115</u>	<u>19,728</u>
12 Subtotal	21,454,631	-20,424,857	1,029,774
13 Shortfall Recovery	6,129,646	-6,129,646	0
14 Return on Costs	<u>2,668,901</u>	<u>-2,668,901</u>	<u>0</u>
15 Total DSM Expenses Incl 920/921	\$30,253,178	-\$29,223,404	\$1,029,774
16 Less 920/921 Expenses	<u>-13,811</u>	<u>0</u>	<u>-13,811</u>
17 DSM Expenses in Account 910	\$30,239,367	-\$29,223,404	\$1,015,963

\* Source: HECO-WP-1104, p. 1 of 12.

\*\* Source: HECO-R-1004, Base Labor includes \$13,811 in Account 920/921 expenses. These are the revised test year estimates of the expenses to be included in base rates, based on HECO's understanding that other costs relating to the existing energy efficiency and load management DSM programs (as well as shareholder incentives, and lost margins for program impacts not reflected in test year sales) will continue to be recovered through a DSM surcharge; provided there continues to be a mechanism (such as a surcharge) for recovering incremental program costs and utility incentives, if any, resulting from DSM programs (and associated cost recovery mechanisms) approved after the rate case (for example, as a result of the Energy Efficiency Docket No. 05-0069).

Company, Inc.

**Proposed in Base Rates (\$)**

imony

REVISED DSM Expense in Base Rates	Rebuttal Revisions	REVISED DSM Expense in Base Rates**
340,742	-3,405	337,337
203,900	7,367	211,267
325,000	0	325,000
13,500		13,500
542,400	7,367	549,767
119,443	-8,001	111,442
25,000	0	25,000
6,228		6,228
150,671	-8,001	142,670
1,033,813	-4,039	1,029,774

Hawaiian Electric Company, Inc.

**Non-DSM Customer Assistance Expense**  
Rebuttal Testimony

Line		<u>\$000s</u>
1	Non-DSM Customer Assistance Expense	4,279
2	Less: Green Pricing Program	-100
3	Add: Customer Solutions Reorganization	<u>399</u>
4	Rebuttal Non-DSM Customer Assistance Expense	4,578

Source

Line 1	HECO-1010
Line 2	CA-101, Schedule C-24
Line 3	HECO-RWP-1005

Hawaiian Electric Company, Inc.

**Informational Advertising Expense**  
**Energy Efficiency and Conservation**  
Rebuttal Testimony

<u>Description</u>	<u>Budget*</u>
Production of TV, radio, print, and direct marketing messages	\$150,000
Broadcast Media (TV, radio)	\$600,000
Print Media (Newspaper, Periodicals)	\$150,000
Direct Marketing / Other	\$100,000
Total Corporate Advertising Budget	<u>\$1,000,000</u>

Source: CA-IR-533

\* Does not include other non-labor informational advertising expense.  
Total non-labor Informational Advertising Expense is \$1,071,000.  
See HECO-R-1001.

## HAWAIIAN ELECTRIC COMPANY, INC.

CUSTOMER SERVICE EXPENSE  
**REBUTTAL** 2005 TEST YEAR  
DSM vs. NON DSM EXPENSES  
(\$1000s)

<u>Line</u>			<u>A</u>	<u>B</u>	<u>C</u>	<u>D</u>
			<u>DSM</u>	<u>NONDSM</u>	<u>GL CODE</u>	<u>TEST YEAR ESTIMATE</u>
1	909	Supervision		39	(8)	31
2	910	Customer Assistance	1,016	4,578	(1,456)	4,138
3	911	Informational Advertising		1,084	(3)	1,081
4	912	Miscellaneous Customer Service		39	(5)	34
5		TOTAL	1,016	5,740	(1,472)	5,284

SOURCE

Column A: HECO-R-1003

Column B: For Accounts 909 and 912: HECO-1002

For Account 910: HECO-R-1005

For Account 911: HECO-R-1002

Column C: HECO-1002

Column D: Columns (A+B+C)

Hawaiian Electric Company, Inc.

**Customer Service Expense Comparison (\$000)**  
**HECO Rebuttal vs. CA Testimony**

	A	B		C
	<b>HECO Rebuttal</b>	<b>CA</b>	<b>(Source)</b>	<b>A - B Difference</b>
HECO Direct (Starting Point)				
Customer Services Expense	33,458	33,458	HECO-1001	
<b>Customer Services Expense</b>				
Remove DSM Expense	-29,223	-30,253	CA-101, C-17*	1,030
Reduce for Standard Labor Rates	0	-14	CA-101, C-20	14
Remove Green Pricing	-100	-100	CA-101, C-24**	0
Add Cust Solutions Reorg	399	505	CA-101, C-19	-106
Add Informational Advertising	750	0		750
Reduce for Vacant Positions	<u>0</u>	<u>-272</u>	CA-101, C-21***	<u>272</u>
Total CA Cust Svc Adjustment	-28,174	-30,134		
<b>910 Expense Estimate</b>	<b>5,284</b>	<b>3,324</b>		<b>1,960</b>

HECO Rebuttal: See HECO-R-1002

\* CA's reduction includes \$14K of related 920/921 expenses.

\*\* The CA shows this adjustment in the Customer Accounts block of accounts.

\*\*\* Includes 8 vacancies in ESD/IRP, of which 3 non-IRP/DSM, 1 IRP, and 4 DSM.

Hawaiian Electric Company, Inc.

**Customer Service Expense Comparison (\$000)**  
**HECO Rebuttal vs. DOD Testimony**

	A	B		C
	HECO Rebuttal	DOD	(Source)	A - B Difference
HECO Direct (Starting Point) Customer Services Expense	33,458	33,458	HECO-1001	
<b>Customer Services Expense</b>				
Remove DSM Expense	-29,223	-30,253	DOD-116*	1,030
Reduce for Standard Labor Rates	0	0		0
Remove Green Pricing	-100	0		-100
Add Cust Solutions Reorg	399	505	DOD-121	-106
Add Informational Advertising	750	0		750
Reduce for Vacant Positions	<u>0</u>	<u>-272</u>	DOD-118**	<u>272</u>
Total CA Cust Svc Adjustment	-28,174	-30,020		
<b>910 Expense Estimate</b>	<b>5,284</b>	<b>3,438</b>		<b>1,846</b>

HECO Rebuttal: See HECO-R-1002

\* DOD's reduction includes \$14K of related 920/921 expenses.

\*\* Includes 8 vacancies in ESD/IRP, of which 3 non-IRP/DSM, 1 IRP, and 4 DSM.

Hawaiian Electric Company, Inc.

**Customer Solutions Employee Count**  
**Actual vs Test Year**

	27-Jul-05 <u>Actual *</u>	2005 Test <u>Year **</u>	27-Jul-05 <u>Vacant</u>	<u>Notes</u>
VP Customer Solutions	2	2	0	
Energy Services Department				
Administration	3	3	0	
Customer Efficiency Programs/Pricing	12	14	2	a)
Marketing Services Division	12	12	0	
Forecasts & Research Division	10	10	0	
Integrated Resource Planning Division	4	5	1	b)
Customer Technology Applications Division	<u>9</u>	<u>10</u>	<u>1</u>	c)
Total	52	56	4	

## Notes on Vacancies:

- a) CIDLC Program Manager -- Ad placed in 6/26/05 Sunday Advertiser.  
Interviews scheduled for week of 8/1/05  
Load Management Program Engineer -- Request for Executive Staffing  
Committee approval to be submitted by Aug 31, 2005 and position filled  
by year-end 2005.
- b) One Senior Resource Planning Analyst position filled on 7/11/05.  
The final Senior Resource Planning Analyst position filled on 8/1/05.
- c) Senior Technical Services Engineer position will be filled by year-end 2005.

## Source:

- \* HECO-R-1603  
\*\* CA-IR-510

## Hawaiian Electric Company, Inc.

**Correction to CA's and DOD's Adjustment for "Open" Positions (\$)**  
**Customer Service Expense**

	<u>Wages*</u>	<u>Non-DSM</u>	<u>DSM Only</u>
<u>Energy Services</u>			
1 CTAD Senior Technical Engineer	65,669	65,669	
2 RDLC Program Manager	65,669		65,669
3 Marketing Services Coordinator	52,569	52,569	
4 DSM Clerk	52,569		52,569
5 Planning Analyst	63,430	63,430	
6 Load Management Engineer	65,669		65,669
7 CIDLC Program Manager	65,669		65,669
8 Senior Resource Planning Analyst	23,500	23,500	
9 Total Wages	454,744	205,168	249,576
Total DSM Wages =			249,576
Adjustment to CA-101, Adj C-21, using CA's 50% methodology			124,788
= Amount Double-Counted by the CA			
CA's Adjustment (CA-101, Adj C-21)			272,000
Revised CA's Adjustment			147,212

\* Expense Elements 150 &amp; 421

NOTE: HECO does not agree that any adjustment for "open" positions is reasonable. However, should the Commission determine that such an adjustment is necessary, the CA's and DOD's proposed adjustment should be reduced as shown.

Hawaiian Electric Company, Inc.

**2005 TEST YEAR ENERGY COST ADJUSTMENT FACTORS  
REBUTTAL TESTIMONY**

<b>ENERGY COST ADJUSTMENT FACTOR CURRENT EFFECTIVE RATES</b>	<b>ENERGY COST ADJUSTMENT FACTOR PROPOSED RATES</b>
<hr/>	<hr/>
5.414    ¢/KWH	0.000    ¢/KWH

Source: HECO-RWP-1012

**Hawaiian Electric Company, Inc.**  
**ENERGY COST ADJUSTMENT FILING MODIFIED FOR DG**  
**Current Effective Rates**

HECO-R-1012  
DOCKET NO. 04-0113  
PAGE 2 OF 3

<u>Line</u>	<u>Effective Date</u>	<u>2005 Norm. Test Year Rebuttal</u>	<u>Line</u>		
1	Effective Date	2005 Norm. Test Year Rebuttal			
2	Supercedes Factor	-			
<b><u>GENERATION COMPONENT</u></b>			<b><u>PURCHASED ENERGY COMPONENT</u></b>		
FUEL PRICES, ¢/MBTU			PURCHASED ENERGY PRICE - ¢/KWH		
3	Honolulu	906.67	35	THC	- On Peak 12.020
4	Kahe	866.89	36		- Off Peak 9.130
5	Waiau-Steam	866.89	37	HRRV	- On Peak 10.817
6	Waiau-Waste	0.00	38		- Off Peak 8.247
7	Waiau-Diesel	1,356.23	39	HRRV	- On Peak (excess) 10.817
			40		- Off Peak (excess) 8.247
	BTU MIX, %		41	Chevron	- On Peak 12.020
8	Honolulu	2.98	42		- Off Peak 9.130
9	Kahe	70.06	43	Kalaeloa	7.612
10	Waiau-Steam	26.64	44	AES-HI	2.549
11	Waiau-Waste	0.00			
12	Waiau-Diesel	0.32			
			PURCHASED ENERGY KWH MIX, %		
13	COMPOSITE COST OF GENERATION, ¢/MBTU	869.64	45	THC	- On Peak 0.11
14	% Input to system kWh Mix	58.41	46		- Off Peak 0.08
15	Generation Efficiency Factor, Mbtu/kWh	0.011170	47	HRRV	- On Peak 5.79
16	WEIGHTED COMPOSITE GEN COST, ¢/kWh (Line 13 x 14 x 15)	5.67388	48		- Off Peak 2.57
			49	HRRV	- On Peak (excess) 0.00
17	BASE GENERATION COST, ¢/Mbtu	287.83	50		- Off Peak (excess) 1.56
18	Base % Input to System kWh Mix	58.64	51	Chevron	- On Peak 0.01
19	Efficiency Factor, Mbtu/kWh	0.011170	52		- Off Peak 0.01
20	WEIGHTED BASE GEN COST, ¢/kWh (Line 17 x 18 x 19)	1.88531	53	Kalaeloa	45.19
			54	AES-HI	44.68
21	Cost Less Base (Line 16 - 20)	3.78857			
22	Revenue Tax Req Multiplier	1.0975			
23	GENERATION FACTOR, ¢/KWH (Line 21 x 22)	4.15796	55	COMPOSITE COST OF PURCHASED ENERGY, ¢/KWH	5.568
<b><u>DG ENERGY COMPONENT</u></b>			56	% Input to System kWh Mix	41.50
24	COMPOSITE COST OF DG ENERGY, ¢/kWh	14.076	57	WTD CMP PURCH ENRGY COST, ¢/KWH (Line 55 x 56)	2.31072
25	% Input to System kWh Mix	0.09			
26	WTD COMP DG ENRGY COST, ¢/KWH (Line 24 x 25)	0.01267	58	BASE PURCH ENERGY COMP COST	3.005
27	BASE DG ENERGY COMP COST	0.000	59	Base % Input to System kWh Mix	41.36
28	Base % Input to System kWh Mix	0.00	60	WTD BASE PRCH ENERGY COST, ¢/KWH (Line 58 x 59)	1.24287
29	WTD BASE DG ENERGY COST, ¢/KWH (Line 27 x 28)	0.00000			
30	Cost Less Base (Line 26 - 29)	0.01267			
31	Loss Factor	1.059	61	Cost Less Base (Line 57 - 60)	1.06785
32	Revenue Tax Req Multiplier	1.0975	62	Loss Factor	1.059
33	DG FACTOR, ¢/KWH (Line 30 x 31 x 32)	0.01473	63	Revenue Tax Req Multiplier	1.0975
34	TOTAL GENERATION FACTOR ¢/KWH (Line 23 + 33)	4.17269	64	PURCHASED ENERGY FACTOR, ¢/KWH (Line 61 x 62 x 63)	1.24111
<u>Line</u>	<b><u>SYSTEM COMPOSITE</u></b>				
65	Total Generation and Purchased Energy Factor (Line 34 + 64)			5.41380	
66	Adjustment, ¢/kWh			0.000	
67	ECA Reconciliation Adjustment, ¢/kWh			0.000	
68	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH (Line 65 + 66 + 67)			5.414	

Source: HECO-RWP-1012

Hawaiian Electric Company, Inc.  
ENERGY COST ADJUSTMENT FILING MODIFIED FOR DG  
Proposed Rates

HECO-R-1012  
DOCKET NO. 04-0113  
PAGE 3 OF 3

Line			Line		
1	Effective Date	2005 Norm. Test Year Rebuttal			
2	Supercedes Factor	-			
<b>GENERATION COMPONENT</b>			<b>PURCHASED ENERGY COMPONENT</b>		
FUEL PRICES, ¢/MBTU			PURCHASED ENERGY PRICE - ¢/KWH		
3	Honolulu	906.67	35	THC	- On Peak 12.020
4	Kahe	866.89	36		- Off Peak 9.130
5	Waiau-Steam	866.89	37	HRRV	- On Peak 10.817
6	Waiau-Waste	0.00	38		- Off Peak 8.247
7	Waiau-Diesel	1,356.23	39	HRRV	- On Peak (excess) 10.817
			40		- Off Peak (excess) 8.247
	BTU MIX, %		41	Chevron	- On Peak 12.020
8	Honolulu	2.98	42		- Off Peak 9.130
9	Kahe	70.06	43	Kalaeloa	7.612
10	Waiau-Steam	26.64	44	AES-HI	2.549
11	Waiau-Waste	0.00			
12	Waiau-Diesel	0.32			
COMPOSITE COST OF			PURCHASED ENERGY KWH MIX, %		
13	GENERATION, ¢/MBTU	869.64	45	THC	- On Peak 0.11
14	% Input to system kWh Mix	58.41	46		- Off Peak 0.08
15	Generation Efficiency Factor, Mbtu/kWh	0.011140	47	HRRV	- On Peak 5.79
16	WEIGHTED COMPOSITE GEN COST, ¢/kWh (Line 13 x 14 x 15)	5.65864	48		- Off Peak 2.57
			49	HRRV	- On Peak (excess) 0.00
17	BASE GENERATION COST, ¢/Mbtu	869.64	50		- Off Peak (excess) 1.56
18	Base % Input to System kWh Mix	58.41	51	Chevron	- On Peak 0.01
19	Efficiency Factor, Mbtu/kWh	0.011140	52		- Off Peak 0.01
20	WEIGHTED BASE GEN COST, ¢/kWh (Line 17 x 18 x 19)	5.65864	53	Kalaeloa	45.19
			54	AES-HI	44.68
21	Cost Less Base (Line 16 - 20)	0.00000			
22	Revenue Tax Req Multiplier	1.0975			
23	GENERATION FACTOR, ¢/KWH (Line 21 x 22)	0.00000	55	COMPOSITE COST OF PURCHASED ENERGY, ¢/KWH	5.568
<b>DG ENERGY COMPONENT</b>			56	% Input to System kWh Mix	41.50
24	COMPOSITE COST OF DG ENERGY, ¢/KWh	14.076	57	WTD CMP PURCH ENRGY COST, ¢/KWH (Line 55 x 56)	2.31072
25	% Input to System kWh Mix	0.09			
26	WTD COMP DG ENRGY COST, ¢/KWH (Line 24 x 25)	0.01267			
27	BASE DG ENERGY COMP COST	14.076	58	BASE PURCH ENERGY COMP COST	5.568
28	Base % Input to System kWh Mix	0.09	59	Base % Input to System kWh Mix	41.50
29	WTD BASE DG ENERGY COST, ¢/KWH (Line 27 x 28)	0.01267	60	WTD BASE PRCH ENERGY COST, ¢/KWH (Line 58 x 59)	2.31072
30	Cost Less Base (Line 26 - 29)	0.00000			
31	Loss Factor	1.051	61	Cost Less Base (Line 57 - 60)	0.00000
32	Revenue Tax Req Multiplier	1.0975	62	Loss Factor	1.051
33	DG FACTOR, ¢/KWH (Line 30 x 31 x 32)	0.00000	63	Revenue Tax Req Multiplier	1.0975
34	TOTAL GENERATION FACTOR ¢/KWH (Line 23 + 33)	0.00000	64	PURCHASED ENERGY FACTOR, ¢/KWH (Line 61 x 62 x 63)	0.00000

Line **SYSTEM COMPOSITE**

35 Total Generation and Purchased Energy Factor (Line 34 x 64) 0.00000

Hawaiian Electric Company, Inc.

**Comparison of Rebuttal Testimony versus  
Direct Testimony Energy Cost Adjustment Factors  
(¢/kwh)**

<b>Present Rates</b>		
<u>Rebuttal Testimony</u>	<u>Direct Testimony</u>	<u>Difference</u>
5.414	2.586	2.828

<b>Proposed Rates</b>		
<u>Rebuttal Testimony</u>	<u>Direct Testimony</u>	<u>Difference</u>
0.000	0.000	0.000

Hawaiian Electric Company, Inc.

**Comparison of 2005 Test Year**

Cost of Service Study - Estimated Present Rates

<u>HECO Rebuttal</u>	<u>CA 1</u>	<u>Difference</u>
5.414	5.789	-0.375

Hawaiian Electric Company, Inc.  
Determination of Composite Cost of Total (Central Station and DG) Generation  
For Avoided Cost Calculation Purposes  
2005 Test Year Rebuttal

<u>Line</u>	<u>CENTRAL STATION ENERGY COMPONENT</u>	<u>Line</u>	<u>DG ENERGY COMPONENT</u>
1	Composite Cost of Generation 869.64 ¢/Mbtu	4	Composite Cost of DG Generation 1431.49 ¢/Mbtu
2	Percent of Generation Btu Mix 99.86 %	5	Percent of DG Btu Mix (100 - line 2) 0.14 %
3	Weighted Composite Cost of Central Station (line 1 x line 2) 868.4225 ¢/Mbtu	6	Weighted Composite Cost of DG (line 4 x line 5) 2.0041 ¢/Mbtu
<u>Line Total Generation Composite Cost</u>			
7	Composite Cost of Central Station and DG (line 3 + line 6)		870.43 ¢/Mbtu

Source: HECO-RWP-1012

Line 1: HECO-RWP-1012 page 10, line 13  
Line 2: HECO-RWP-1012 page 5, line 16  
Line 4: HECO-RWP-1012 page 4, line 5  
Line 5: HECO-RWP-1012 page 5, line 17

Hawaiian Electric Company, Inc.

DERIVATION OF TEST YEAR 2005 REBUTTAL  
AVOIDED ENERGY COST PAYMENT RATES

Avoided Energy Rate - over 100 KW

Line	ON-PEAK	OFF-PEAK	SOURCE
1 Heat Rate	13,382 BTU / NET KWH	9,929 BTU / NET KWH	Docket #4569, HECO-101
2 Composite Fuel Cost of Total Generation (HECO & DG)	870.43 ¢ / MMBTU	870.43 ¢ / MMBTU	Test Year 2005 Rebuttal Composite Fuel Cost.
3 1 MMBTU / 1,000,000 BTU	1,000,000 BTU / MMBTU	1,000,000 BTU / MMBTU	
4 Unadjusted Payment Rate (line 1 x 2) / line 3	11.65 ¢ / NET KWH	8.64 ¢ / NET KWH	
5 O&M Adjustment	<u>0.37</u> ¢ / NET KWH	<u>0.49</u> ¢ / NET KWH	Appendix A, D&O 8298
6 BASE Avoided Energy Payment Rate	<u>12.02</u> ¢ / NET KWH	<u>9.13</u> ¢ / NET KWH	

Source: HECO-RWP-1012

Hawaiian Electric Company, Inc.

**Comparison of Rebuttal Testimony versus  
Direct Testimony Sales Heat Rate  
(btu/kwh sales)**

<u>Rebuttal Testimony</u>	<u>Direct Testimony</u>	<u>Difference</u>
11,140	11,077	63

Hawaiian Electric Company, Inc.

**Comparison of 2005 Test Year  
Sales Heat Rate  
(btu/kwh sales)**

<u>HECO Rebuttal <sup>1</sup></u>	<u>CA <sup>2</sup></u>	<u>Difference</u>
11,140	11,072	68

<sup>1</sup> HECO-R-406, line 18.

<sup>2</sup> CA-301, col. C, line 7.

Hawaiian Electric Company, Inc.

**Actual Incremental IRP General Planning Costs**  
1995-2004

<u>Year</u>	HECO IRP
	<u>Incremental Cost</u> <u>Recovery</u>
1995	\$950,549
1996	\$664,598
1997	\$849,225
1998	\$160,012
1999	\$141,633
2000	\$97,125
2001	\$57,592
2002	\$162,405
2003	\$381,240
2004	<u>\$632,033</u>
	<b><u>\$4,096,412</u></b>

Source: Annual IRP Cost Recovery Filings

REBUTTAL TESTIMONY OF  
FAYE K. YAMAUCHI

DIRECTOR, COST ACCOUNTING  
GENERAL ACCOUNTING  
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Administrative & General Expense;  
Amortization of Kahe Unit 7  
Project Costs

INTRODUCTION

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15  
16  
17  
18  
19  
20  
21  
22  
23  
24  
25

- Q. Please state your name and business address.
- A. My name is Faye K. Yamauchi and my business address is 900 Richards Street, Honolulu, Hawaii.
- Q. What is your position with Hawaiian Electric Company, Inc. ("HECO")?
- A. I am HECO's Director of Cost Accounting.
- Q. What is your area of responsibility in this proceeding?
- A. My testimony, HECO RT-13, covers Administrative & General (A&G) Expense and the Amortization of Kahe Unit 7 Project Costs.
- Q. Have you previously submitted testimony in this proceeding?
- A. No, I have not.
- Q. Are you replacing Ernest T. Shiraki as a witness in this proceeding?
- A. Yes, to a certain extent. Mr. Shiraki retired as of May 1, 2005, and I have been assigned the A&G Expense portion of his rate case responsibilities. I am adopting that portion of Mr. Shiraki's testimony marked as HECO T-13. My educational background and experience are provided in HECO- R-1300. The balance of Mr. Shiraki's rate case responsibilities has been assigned to Ms. Tayne Sekimura (HECO RT-16).
- Q. Are you also adopting certain portions of the direct testimony of Ms. Tayne Sekimura in this docket?
- A. Yes, besides the A&G Expense portion of Mr. Shiraki's rate case responsibilities, I have been assigned the Miscellaneous Administrative and General Expenses portion of Ms. Sekimura's rate case responsibilities. I have, therefore, adopted that portion of Ms. Sekimura's testimony marked as HECO T-16 and have incorporated rebuttal testimony related to Miscellaneous A&G Expenses into my

1            rebuttal testimony, HECO RT-13.

2 Q. What is the scope of your rebuttal testimony?

3       A.   My rebuttal testimony will:

- 4 1) Summarize HECO's overall rebuttal position with respect to A&G Expenses,  
5 2) Address the Company's rebuttal position with respect to the A&G Expense  
6 accounts for which I am responsible, i.e. the accounts for Administrative  
7 Expenses (Account Nos. 920, 921 and 922), Outside Services (Account Nos.  
8 923010 and 923020), Employee Benefits Transferred (Account No. 926020)  
9 and Miscellaneous A&G Expenses (Account Nos. 928-932), and  
0 3) Address the Company's rebuttal position with respect to the amortization of  
1 Kahe Unit 7 project costs.

2 Q. How is your rebuttal testimony organized?

3 A. I will:

- 1) Summarize HECO's rebuttal position, including revisions made to the Company's direct testimony estimates in preparing its rebuttal position,
- 2) List and summarize the areas where the Consumer Advocate (CA) and HECO agree, and/or the Department of Defense (DOD) and HECO agree,
- 3) List the areas where the CA and HECO disagree, and/or the DOD and HECO disagree, and
- 4) Discuss each area of disagreement.

1 HECO'S REBUTTAL POSITION

Q. What is HECO's overall rebuttal position with respect to A&G Expenses?

3       A.   HECO's normalized test year 2005 estimate for total A&G Expenses is  
4       \$55,277,000 as detailed in HECO-R-1301.

5 Q. Do any of the rebuttal estimates for A&G Expenses reflect adjustments to the

1 Company's direct testimony estimates?

2 A. Yes, the Company's direct testimony estimates were adjusted as shown in HECO-  
3 R-1301.

4 Q. In general, why did the Company adjust its direct testimony estimates?

5 A. The adjustments were made for a variety of reasons, including changes to reflect  
6 later information, to correct forecast errors, to reflect changes made by other  
7 witnesses which, in turn, affect certain A&G expense accounts, and to reduce the  
8 number of issues in this case.

9 Q. What are the specific reasons for the HECO adjustments?

10 A. HECO-R-1301 includes a brief description of the changes for which I am  
11 responsible, as well as references to documents which provide more details on the  
12 nature of the adjustments. Changes made by other witnesses are addressed by  
13 those witnesses.

14 AREAS OF AGREEMENT

15 Q. Where are the CA, DOD and HECO in agreement?

16 A. With respect to the A&G Expenses for which I am responsible (i.e. Account Nos.  
17 920, 921, 922, 923010, 923020, 926020 and 928-932), it appears that the CA,  
18 DOD and HECO agree on the test year 2005 expense estimates for the following  
19 accounts:

20 1) 923010 - Outside Services - Legal,

21 2) 923020 - Outside Services – Other (Note: The \$1,000 difference between the  
22 Company and Consumer Advocate shown on HECO-R-1301 is due to  
23 rounding),

24 3) 9301 – Institutional or Goodwill Advertising Expense, and

25 4) 932 – A&G Maintenance.

1 Q. Are there any other areas not specifically related to A&G expenses where the  
2 CA, DOD and HECO are in agreement?

3 A. Yes, the CA and DOD are in agreement with HECO's use of Standard Labor  
4 Rates in determining the Company's labor cost estimates. All three parties are  
5 also in agreement with the Standard Labor Rate Adjustment amount that was  
6 presented in HECO's response to DOD/HECO-IR-9-18.

7 Standard Labor Rate Adjustment:

8 Q. What is the Standard Labor Rate Adjustment?

9 A. To determine the standard labor rates used to calculate the estimated 2005 test  
10 year labor costs, HECO started with 2003 actual data (i.e. actual productive labor  
11 dollars and hours) as the base year. The 2003 standard labor rates were then  
12 adjusted to reflect wage increases granted or to be granted in 2004 and 2005. In  
13 reviewing HECO's standard labor rate determination process, the Consumer  
14 Advocate expressed concern about HECO's test year 2005 O&M labor costs in  
15 that the actual 2003 mix of productive overtime and regular time hours used by  
16 HECO as the base year was not necessarily representative of the test year 2005  
17 mix of productive overtime and regular time hours. Following several  
18 conference calls, HECO quantified a possible adjustment to more accurately  
19 reflect the proportionate mix of test year 2005 productive overtime and regular  
20 time hours in the base standard labor rates and in test year labor costs. The  
21 quantified adjustment amounts to a reduction in test year O&M expenses by  
22 \$246,000. The documentation and work papers for the quantification of the  
23 adjustment were provided in the Company's response to DOD/HECO-IR-9-18.

24 Q. Did the Consumer Advocate and the Department of Defense make a Standard  
25 Labor Rate Adjustment?

- 1       A.     The Consumer Advocate and Department of Defense have accepted HECO's use  
2             of Standard Labor Rates to determine the test year estimates with the adjustment  
3             calculated by HECO. The Consumer Advocate and the DOD accepted the  
4             adjustment to reduce O&M expenses by \$246,000 as provided in the Company's  
5             response to DOD/HECO-IR-9-18. The Consumer Advocate then allocated the  
6             \$246,000 to the various functional blocks of accounts (i.e., Production O&M,  
7             Transmission O&M, Distribution O&M, Customer Accounts, Customer Service,  
8             and A&G Expenses) based on the labor charges for each block of account  
9             reflected in HECO's direct testimony estimates. The Consumer Advocate also  
10            made an adjustment of \$19,000 to Taxes Other Than Income Taxes to reduce  
11            payroll taxes related to the Standard Labor Rate Adjustment.
- 12       Q.     How has the DOD reflected the Standard Labor Rate Adjustment?
- 13       A.     The DOD reflected a reduction of \$264,000, which includes the O&M expense  
14             adjustment of \$246,000 and \$18,000 for payroll taxes.
- 15       Q.     Has HECO included a Standard Labor Rate Adjustment in its rebuttal results of  
16             operations?
- 17       A.     Yes, HECO has reflected the Standard Labor Rate Adjustment as quantified in  
18             its response to DOD/HECO- IR-9-18. However, HECO has reflected the  
19             adjustment as a separate line item on the Results of Operations rather than  
20             reflecting the amount in each O&M block of account or in one block of account.  
21             (HECO has also reflected an adjustment to Taxes Other Than Income Taxes of  
22             \$20,000 for the related impact on payroll taxes.) The Consumer Advocate's  
23             allocation method (based on total labor charges) is not the best method to  
24             allocate the adjustment. A better method of allocating the adjustment would be  
25             to base the allocation on the bargaining unit labor dollars in each block of

1 account, since that is the group of employees that would have generated  
2 (received) the overtime pay (generally merit employees do not get overtime pay).  
3 However, bargaining unit overtime labor cost information by block of account is  
4 not easily obtainable, since costs are not separately tracked by bargaining unit  
5 employees and merit employees. Given that the Standard Labor Rate  
6 Adjustment is less than one percent of the total test year O&M labor costs, not  
7 allocating the costs to blocks of accounts does not significantly distort the costs  
8 for each block of account. Allocating the costs to one block of account (as done  
9 by the Department of Defense) is probably less representative of where the  
10 adjustment should be reflected. HECO prefers to reflect the adjustment as a  
11 separate line item, however, if the parties insist on an allocation, HECO will  
12 consider the CA's allocation as a possible proxy.

13 AREAS OF DISAGREEMENT

14 Q. With respect to the A&G Expenses for which you are responsible, where do the  
15 CA and/or DOD disagree with HECO's normalized test year 2005 estimates?

16 A. The areas of disagreement involve the following accounts as shown in HECO-R-  
17 1301:

- 18 1) 920 - A&G Expense - Labor
- 19 2) 921 - A&G Expense - Non Labor
- 20 3) 922 - A&G Expenses Transferred
- 21 4) 926020 - Employee Benefits Transfer
- 22 5) 928 - Regulatory Commission Expenses
- 23 6) 9302 - Miscellaneous General Expenses
- 24 7) 931 - Rents Expense - A&G

25 Q. Do you address any areas of disagreement outside of the A&G expense group of

1 account numbers?

2 A. Yes. I address the difference between the Company and both the CA and DOD  
3 with respect to the amortization of the Kahe Unit 7 project costs, which  
4 amortization is charged to Production Operation expense.

5 ADMINISTRATIVE & GENERAL EXPENSES

6 Q. With respect to the A&G expenses for which you are responsible, how will you  
7 address the differences in test year 2005 estimates between the parties?

8 A. To facilitate the discussion of the differences between the parties, the differences

1 920, and the test year estimates proposed by the Consumer Advocate and  
2 Department of Defense?

3 A. Yes. The CA's test year estimate for Account No. 920 is \$13,605,000, which is  
4 \$251,000 lower than the Company's estimate. The DOD's test year estimate is  
5 \$13,460,000, which is \$396,000 lower than the Company's estimate (see HECO-  
6 R-1301).

7 Q. What are the reasons for the differences?

8 A. The \$251,000 and \$396,000 differences are made up of the items shown below.  
9 The company's estimate is higher (lower) than the CA's or DOD's estimates.

10		<u>CA Difference</u>	<u>DOD Difference</u>
11	1) Customer Solutions Reorganization	\$ (69,000)	\$ (69,000)
12	2) Standard Labor Rate Adjustment	61,000	264,000

---

13	3) Employee Count Adjustment	201,000	201,000
14	4) Incremental IRP planning costs	<u>58,000</u>	<u>0</u>
15	Total difference	<u>\$251,000</u>	<u>\$396,000</u>

16 Customer Solutions Reorganization

17 Q. What is the (\$69,000) issue with respect to the Customer Solutions  
18 Reorganization?

19 A. As part of the Customer Solutions reorganization addressed in HECO's response  
20 to CA-IR-78, the Company eliminated the Director of Forecast position and,  
21 accordingly, reduced labor costs charged to Account No. 920 by the related  
22 \$69,000. Apparently, neither the CA nor the DOD reflected HECO's \$69,000  
23 reduction in their test year estimates. As part of the Customer Solutions  
24 reorganization, HECO also identified a need to increase costs to Account No. 910

1 Solutions reorganization in CA-101, Schedule C-19 but reflected the increase in  
2 A&G expenses on Exhibit CA-101, Schedule C, page 4 of 5. The CA has  
3 recognized this posting error in its response to HECO/CA-IR-212 and the increase  
4 should be reflected in the line above A&G, which is the Customer Service line.

5 Standard Labor Rate Adjustment

6 Q. Is the reason for the CA (\$61,000) and DOD (\$264,000) differences shown under  
7 the Standard Labor Rate Adjustment above related to an earlier discussion in this  
8 rebuttal testimony with respect to the Standard Labor Rate Adjustment?

9 A. Yes, the apparent differences (but there is no real issue between the parties) are  
10 because the parties chose to include the Standard Labor Rate Adjustment in  
11 different parts of their test year estimates. As discussed earlier in this rebuttal  
12 testimony, the Standard Labor Rate Adjustment resulted in a total reduction to  
13 operation and maintenance expense labor costs of \$245,638 (\$264,429 including  
14 payroll taxes). The CA allocated the adjustment to the major expense categories  
15 as shown in Exhibit CA-101, Schedule C, page 4, under column E, including a  
16 \$61,000 reduction to Account No. 920. The DOD applied the total \$264,000  
17 Standard Labor Rate Adjustment as a reduction to Account No. 920. The  
18 Company, on the other hand, applied the reduction of \$246,000 as a one line item  
19 adjustment on its Results of Operations and an adjustment to Taxes Other Than  
20 Income Taxes of \$20,000 for the related impact on payroll taxes.

21 Employee Count Adjustment

22 Q. What is the \$201,000 issue with respect to the employee count adjustment?

23 A. The CA is proposing a \$1,599,000 reduction to the Company's direct testimony  
24 estimate of operation and maintenance expenses to reflect an adjustment for  
25 average employee count levels (the DOD proposes the same adjustment). The

1 \$1,599,000 includes a proposed \$201,000 reduction to the Company's direct  
2 testimony estimate for Account Nos. 920 through 9302, i.e. to A&G labor (see CA  
3 Schedule C-21, line 7). The Company's overall position with respect to the  
4 employee count issue is addressed by Ms. Tayne Sekimura in HECO RT-16.

5 Q. With respect to Account No. 920 (A&G labor), are there any approved positions  
6 that are not reflected in, i.e. positions that are in addition to, the Company's  
7 rebuttal testimony estimate of A&G labor costs?

8 A. Yes. A total of twenty (20) net additional positions are identified on HECO-R-  
9 1302. As of June 30, 2005, all 20 additional positions were filled. Some of the  
10 positions were identified in previously filed HECO responses to information  
11 requests, as discussed in HECO-R-1302. The number of additional positions that  
12 relate to the A&G area, by HECO organization, are as follows:

<u>Organization</u>	<u>No. of Additional Positions</u>
1) Corporate Audit & Compliance	6
15 2) Information & Technology Services	5
16 3) Safety, Security & Facilities	3
17 4) Workforce Staffing & Development	1
18 5) Government Relations	1
19 6) Education & Consumer Affairs	1
20 7) VP-Government & Community Affairs	1
21 8) Regulatory Affairs	1
22 9) Technology	<u>1</u>
23 Total Additional Positions	<u>20</u>

24 Q. What do these additional positions suggest with respect to the CA's and DOD's  
25 proposed reduction in A&G labor costs?

1 A. The CA's and DOD's proposed \$201,000 reduction to HECO's test year A&G  
2 labor costs (included as an Account No. 920 issue) is not reasonable, given the  
3 additional positions beyond those included in HECO's rebuttal test year estimate  
4 that are already filled, and the Company's plans to fill currently vacant positions  
5 included in its test year A&G expense estimates as discussed in HECO-R-1302.  
6 The CA's and DOD's proposed reductions to HECO's test year A&G labor costs  
7 will result in rates that are not sufficient to cover the Company's ongoing level of  
8 A&G labor costs.

9 Incremental IRP Planning Costs

10 Q. What is the \$58,000 issue with respect to incremental IRP planning costs?

11 A. The \$58,000 difference between HECO and the Consumer Advocate is shown on  
12 the CA's Schedule C-17, which represents the Consumer Advocate's proposed  
13 adjustment to remove \$30,871,000 of DSM program costs and incremental IRP  
14 planning costs from the Company's test year estimates, which costs the CA claims  
15 should be considered in the separate Docket No. 05-0069 (see CA-T-2, page 56).  
16 Of the Consumer Advocate's total proposed adjustment amount, \$618,000 is for  
17 incremental IRP planning costs, of which \$58,000 is to adjust Account No. 920  
18 and \$560,000 is to adjust Account No. 921.

19 Q. What is the Company's position with respect to the \$618,000 of incremental IRP  
20 costs, and therefore, the \$58,000 included in HECO's test year estimate for  
21 Account No 920?

22 A. The Company's position is addressed by Mr. Alan Hee in HECO RT-10.

23 Account No. 921 – A&G Expense – Non Labor

24 Q. What are the Company's test year estimate and the remaining differences between  
25 the parties with respect to Account No. 921 – A&G Expense – Non Labor?

1 A. The Company's normalized test year estimate for Account No. 921 is  
2 \$11,234,000, after a net decrease of \$344,000 as summarized in HECO-R-1301.  
3 The Consumer Advocate's adjustment to the Company's direct testimony estimate  
4 for Account No. 921 is a net reduction of \$800,000 which is \$456,000 more than  
5 the Company's reduction.

6 Q. What are the reasons for the \$456,000 difference?

7 A. The \$456,000 difference is made up of the following four items:

8	1) Incremental IRP planning costs	\$560,000
9	2) Ellipse upgrade costs	39,000
10	3) Ellipse fee to buy down maintenance costs	51,000*
11	4) Charges in account no. 184120 related to new	
12	phone system	<u>(194,000)</u>
13	Total difference	<u>\$456,000</u>

14 \* \$99,000 CA proposed disallowance allocated to Account No. 921 less HECO  
15 rebuttal adjustment of \$48,000 per HECO-R-1303.

16 Incremental IRP Planning Costs

17 Q. What is the issue with respect to the \$560,000 of incremental IRP planning costs  
18 included in the Company's test year estimate for Account No. 921?

19 A. The issue has been previously described in this testimony under Account No. 920.  
20 The Company's position on this issue is addressed in detail by Mr. Alan Hee in  
21 HECO RT-10.

22 Ellipse Upgrade Costs

23 Q. What is the \$39,000 issue with respect to the Ellipse upgrade costs?

24 A. The Company's test year expense estimates include a normalization adjustment  
25 totaling \$161,000, representing twenty five percent of the cost to periodically  
26 upgrade its core business software system. In other words, the Company

1 anticipates that the software will be upgraded approximately every four years,  
2 based on information provided by Mincom, the software vendor. The current  
3 version of the software is called Ellipse; the previous version was called Mims.  
4 The \$161,000 total normalization adjustment is allocated to several different  
5 expense accounts, including \$39,000 to Account No. 921 and \$92,000 to Account  
6 No. 9302 – Miscellaneous General Expenses (see HECO-1309, page 2). The  
7 Consumer Advocate's test year estimates do not include the \$161,000 of Ellipse  
8 upgrade costs, including the \$39,000 for Account No. 921.

9 Q. Why is the \$161,000 for Ellipse software upgrade costs (\$39,000 for Account No.  
10 921) a proper and necessary cost for the test year?

11 A. Periodic upgrades to the Company's core business software system have occurred  
12 in the past, and will occur in the future. The system was upgraded in 2003 from  
13 Mims to Ellipse, and Mincom's current plan is to retire in 2007 the version of  
14 Ellipse now being used by HECO. The Consumer Advocate does not disagree  
15 with the concept that periodic software upgrades are necessary (see CA-T-2, page  
16 41).

17 Q. Is it reasonable to include the normalization adjustment in test year expenses when  
18 the upgrade will not occur in 2005?

19 A. Yes, because the normalization adjustment represents a reasonable level of  
20 ongoing costs incurred by the Company. The adjustment is not an advance  
21 collection of a future, post-test year cost as claimed by the Consumer Advocate  
22 (see CA-T-2, page 42). While the next upgrade will occur beyond the 2005 test  
23 year, the upcoming upgrade is not a new, first time cost for the Company. Rather,  
24 upgrades have already occurred in the past, and the already established cost  
25 pattern is for an upgrade every few years. Test year expenses would be

1 understated, and cost recovery for an already established periodic cost would be  
2 denied, if a normalized amount of Ellipse upgrade costs is not included in test year  
3 expenses simply because the periodic cost is not actually incurred in 2005.

4 Ellipse Fee to Buy Down Maintenance Costs

5 Q. What is the \$51,000 issue with respect to the fee paid by HECO to buy down the  
6 cost of the annual Ellipse maintenance fee?

7 A. The Company paid to its Ellipse software vendor, and recorded as a pre-paid  
8 expense, a total of \$1.1 million (\$550,000 each in June 2004 and January 2005) in  
9 return for reduced future annual software maintenance fees (see HECO T-16, page  
10 15). HECO has been amortizing the \$1.1 million over a two-year payback period,  
11 and included \$401,000 (its share of the 2005 amortization amount plus general  
12 excise taxes) in test year 2005 expenses. Of the \$401,000 total amortization,  
13 \$99,000 is allocated to Account No. 921 and \$228,000 is allocated to Account No.  
14 9302 – Miscellaneous General Expenses. The Consumer Advocate proposes to  
15 exclude the entire amortization amount from test year expenses (see CA-T-2, page  
16 43).

17 Q. Is it appropriate and reasonable to include in 2005 test year expenses an amount  
18 representing the amortization of the Ellipse maintenance buy-down fee?

19 A. Yes, it is definitely appropriate and reasonable. The Company actually incurred a  
20 pre-paid cost of \$1.1 million plus general excise taxes, which it is amortizing over  
21 a two-year period. Ratepayers benefit from the cost incurred by the Company in  
22 the form of reduced annual Ellipse maintenance fees, presumably at least until the  
23 next software upgrade currently planned by the vendor for September 2007. It  
24 would be inappropriate to include in test year expenses the reduced annual

1 costs incurred by the Company to obtain the ratepayer benefit, i.e. the lower  
2 maintenance fees.

3 Q. Is the Company revising its direct testimony estimate for the test year amortization  
4 amount on rebuttal?

5 A. Yes. As a result of the Consumer Advocate's testimony with respect to this issue,  
6 the Company re-evaluated the two-year amortization period and concluded that  
7 amortizing the Ellipse maintenance buy-down fee over a period up to the next  
8 software upgrade, currently planned by the vendor for September 2007, is more  
9 appropriate than the two-year amortization period.

10 Q. What is the effect of the change in amortization period?

11 A. HECO's portion of the maintenance buy-down fee amortization was revised from  
12 the direct testimony amount of \$401,000 to the rebuttal testimony amount of  
13 \$207,000, a decrease of \$194,000. Of the \$194,000 total reduction, \$48,000 was  
14 allocated to Account No. 921 and \$111,000 was allocated to Account 9302. As a  
15 result of the lower test year amortization amount, there is a net savings to the  
16 ratepayer totaling approximately \$54,000 per year. In other words, HECO's  
17 portion of the maintenance buy-down fee amortization and new lower annual  
18 maintenance fee is \$54,000 per year less than the previous annual maintenance  
19 fee. HECO- R-1303 provides calculations of the Company's revised test year  
20 amortization amount and the net savings to ratepayers.

21 Charges in Account No. 184120 Related to New Phone System

22 Q. What is the nature of the \$194,000 issue with respect to charges in Account No.  
23 184120 related to the Company's new phone system?

24 A. The Company is transitioning to a new phone system during 2005, and  
25 implementing the new system on a phase-in basis. The Company's direct

1 testimony estimate for Account No. 921 included costs related to both the existing  
2 phone system and the new phone system being installed, which is the actual  
3 situation in 2005. However, for ratemaking purposes, the cost of only one phone  
4 system should be reflected in the test year estimate. As a result, the Company  
5 reduced its test year estimate for Account No. 921 by \$194,000 (92% of the  
6 \$210,500 total decrease in estimated Account No. 184120 charges, representing  
7 the portion of Account No. 184120 charges that is allocated to expense) on  
8 rebuttal to include the costs of only the new phone system. This adjustment has  
9 been previously discussed in HECO's response to CA-IR-625. The adjustment  
10 was also identified on Attachment 9 in HECO's letter to the Consumer Advocate  
11 and Department of Defense dated June 15, 2005.

12 Q. What is the difference between the parties with respect to the Company's  
13 \$194,000 reduction in Account No. 921 expenses for the test year?

14 A. Neither the Consumer Advocate nor the Department of Defense included the  
15 Company's adjustment in their test year estimates for Account No. 921. The  
16 Company is assuming that not including the Company's reduction in their  
17 Account No. 921 test year expense estimate was an oversight on the part of the  
18 Consumer Advocate and Department of Defense.

19 Q. Besides the \$194,000 difference between HECO and the DOD mentioned in the  
20 immediately preceding question and answer, are there any remaining differences  
21 between the Company and DOD with respect to the test year estimates for  
22 Account No. 921?

23 A. Yes, as shown on HECO-R-1301, the Company's test year estimate for Account  
24 No. 921 is \$11,234,000 and the Department of Defense's estimate is \$11,489,000.  
25 The DOD's test year estimate is higher than the Company's estimate by \$255,000.

2 remaining difference of \$61,000. The reason for the \$61,000 remaining difference  
3 is as follows (the DOD's test year expense estimate is higher by the amounts  
4 indicated):

5	1) HEI charges to HECO	\$13,000
6	2) Ellipse fee to buy down maintenance costs	<u>\$48,000</u>
7	3) Total	<u>\$61,000</u>

8 Q. What is the nature of the differences?

9 A. On rebuttal, HECO increased its estimate of HEI charges to HECO by a net  
10 \$82,000, while it appears that the DOD inadvertently accepted what it believed to  
11 be a larger HECO increase (the DOD increased its estimate of HEI's charges to

1 is shown in HECO-R-1304. The \$17,000 adjustment on rebuttal is the result of  
2 revisions to the Company's test year estimates for Account Nos. 920 and 921.  
3 The Company is not certain as to what the Consumer Advocate's and Department  
4 of Defense's estimates are for Account No. 922. The CA and DOD appear to  
5 accept the Company's \$2,203,000 (credit) direct testimony estimate for Account  
6 No. 922 even though there are differences between the parties with respect to  
7 Account Nos. 920 and 921. The Company is not aware of any issues with respect  
8 to the methodology it used to calculate the test year estimate for Account No. 922.  
9 If there are no issues with respect to methodology, the differences between the  
10 parties with respect to Account No. 922 would be the result of differences  
11 between the parties with respect to the test year estimates for Account Nos. 920  
12 and 921 as discussed in detail previously in this rebuttal testimony.

13 Account No. 926020 – Employee Benefits Transfer

14 Q. What are the Company's test year estimate and the differences between the parties

---

15 with respect to Account No. 926020 – Employee Benefits Transfer?

16 A. The Company's normalized test year 2005 estimate for Account No. 926020 is a  
17 credit of \$7,380,000 after adding \$141,000 in credits to its direct testimony  
18 estimate on rebuttal. The calculation of the \$7,380,000 test year rebuttal estimate  
19 is shown in HECO-R-1305. The \$141,000 (credit) adjustment on rebuttal is the  
20 result of revisions to the Company's test year estimates for Account Nos. 926000-  
21 Employee Pensions and Benefits and 926010-Employee Benefits-Flex Credits.  
22 Both the CA's and DOD's test year estimate for Account No. 926020 is a credit of  
23 \$7,360,000, a difference of \$20,000 from HECO's estimate. The Company is not



1 by the Consumer Advocate and Department of Defense to the Company's test  
2 year rate case expense amortization amount:

- 3 1) The CA and DOD increased the Company's direct testimony total rate case  
4 expense estimate by \$59,000, versus HECO's increase of \$311,000, a  
5 difference of \$252,000, and  
6 2) The CA and DOD increased the Company's proposed 3 year rate case  
7 amortization period to 4 years.

8 Rate Case Expense Estimate

9 Q. What makes up the \$252,000 difference in estimated total rate case expenses?

10 A. The \$252,000 difference in estimates between HECO and the CA and DOD is  
11 made up of the following two items:

12 1) HECO's estimated legal fees are higher by: \$172,000

13 2) HECO's estimated DSM consultant costs are higher by: 80,000

14 Total difference \$252,000

15 Q. What amount of legal fees is included in the Company's and in the CA's and  
16 DOD's test year rate case expense estimate?

17 A. The Company's estimate is \$377,000, while the CA and DOD used HECO's  
18 direct testimony estimate of \$205,000 (see HECO-R-1306). The CA is using  
19 HECO's \$205,000 direct testimony estimate pending receipt of information in this  
20 rebuttal testimony identifying the portion of the Company's \$377,000 rebuttal  
21 testimony estimate applicable to the DSM Docket No. 05-0069 (see CA-T-2, page  
22 63 and footnote (b) on CA Schedule C-18).

23 Q. What portion of the Company's \$377,000 test year estimate for legal fees is  
24 applicable to DSM Docket No. 05-0069?

25 A. None of the \$377,000 is applicable to the separate DSM Docket. All of the

1           \$377,000 is applicable to this instant Docket No. 04-0113. The Company is  
2           requiring a significant level of support from its outside counsel with respect to this  
3           proceeding. Eventual billings to HECO for outside counsel services provided  
4           through June 2005 are estimated to approximate \$245,000. The Company's  
5           \$205,000 direct testimony estimate of legal fees will certainly be exceeded. In  
6           addition, if hearings are conducted as part of this instant proceeding, the \$377,000

7           of rebuttal testimony estimated legal fees would be exceeded.

8           DSM Consultant Costs

9           Q.   What amount of DSM consultant costs has the Company included in its test year  
10           rate case expense estimate?

11          A.   The Company included \$80,000 for DSM consultant costs (see HECO-R-1306),

1 page 6), contained the following statement on page 2: "HECO also agreed that  
2 the current DSM programs will end as part of the next rate case, and that any  
3 DSM programs to be in place after that rate case will be determined as part of that  
4 case." As a result of that agreement, HECO was obligated to make DSM a part  
5 of this instant Docket, and incurred DSM consultant costs in support of that  
6 commitment.

7 Q. Did the Company continue to incur DSM consultant costs in this instant docket  
8 after the Commission bifurcated DSM related issues to the separate Docket No.  
9 05-0069?

10 A. Yes. As part of the Information Request and Response process in this proceeding,  
11 the Company inquired with the Consumer Advocate as to whether HECO should  
12 defer to the separate Docket No. 05-0069 HECO's responses to DSM related  
13 information requests. In response to the Company's inquiry, the Consumer  
14 Advocate requested that HECO complete its responses to the DSM related  
15 information requests. Therefore, including DSM related consultant costs through  
16 the completion of HECO's responses to Information Requests in this instant  
17 proceeding is appropriate and reasonable.

18 Rate Case Amortization Period

19 Q. What is the difference between the Company and the Consumer Advocate and  
20 Department of Defense with respect to the rate case expense amortization period?

21 A. The Company used a three year amortization period while the CA and DOD are  
22 proposing a four year amortization period.

23 Q. Why is a three year amortization period more reasonable?

24 A. Based on currently existing conditions, several factors would seem to generally  
25 suggest a shorter, rather than longer, time frame before HECO's next rate case

1 filing. These factors include:

- 2 1) Prospects for higher future interest rates,
- 3 2) Increasing maintenance costs due to aging plant,
- 4 3) Significant new capital and software development projects, including the
- 5 Energy Management System, Outage Management System, Customer
- 6 Information System and Human Resources Suite,
- 7 4) Costs for additional Distributed Generation units to mitigate potential reserve
- 8 capacity shortfalls.
- 9 5) Increasing size of HECO's workforce.

10 Q. What is another factor that could reduce, rather than increase, the time before  
11 HECO's next rate case filing?

12 A. The level of rate increase supported by the Consumer Advocate and Department  
13 of Defense, and the rate increase ultimately approved by the Commission in this  
14 proceeding, could have a bearing on the timing of HECO's next rate case filing.  
15 An approved increase significantly lower than HECO's requested increase would  
16 tend to shorten the time before the Company's next rate case filing. On the other  
17 hand, an approved increase close to HECO's requested amount could make a four  
18 year period before HECO's next rate case filing more realistic.

19 Account No. 9302 – Miscellaneous General Expenses

20 Q. What are the Company's test year estimate and the remaining differences between  
21 the parties with respect to Account No. 9302 – Miscellaneous General Expenses?

22 A. The Company's normalized test year 2005 estimate for Account No. 9302 is  
23 \$3,112,000 after a reduction of \$207,000 from its direct testimony estimate (see  
24 HECO-R-1301). The Consumer Advocate, on the other hand, reduced the  
25 Company's direct testimony estimate for Account No. 9302 by a total of

1           \$417,000, which exceeds the Company's decrease by \$210,000.

2       Q.   What are the reasons for the \$210,000 difference?

3       A.   The \$210,000 difference is made up of the following two items:

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

1 periodic cost would be denied, if a normalized amount of Ellipse upgrade costs is  
2 not included in test year expenses.

3 Q. Can you please summarize the earlier testimony with respect to the Ellipse fee to  
4 buy down maintenance costs?

5 A. Yes. The Company paid to its Ellipse software vendor, and recorded as a pre-paid  
6 expense, a \$1.1 million fee in return for reduced future annual software  
7 maintenance fees (see HECO T-16, page 15). HECO has been amortizing its  
8 share of the \$1.1 million fee, plus general excise taxes, over a two-year payback  
9 period, and included \$401,000 in test year 2005 expenses, of which \$229,000 was  
10 allocated to Account No. 9302. Including the fee amortization in test year  
11 expenses is definitely appropriate and reasonable. Ratepayers benefit from the

cost incurred by the Company, i.e. ratepayers benefit from reduced annual Ellipse maintenance fees, presumably at least until the next software upgrade currently planned by the vendor for September 2007. It would be inappropriate to include in test year expenses the reduced annual maintenance fees enjoyed by ratepayers, but exclude from test year expenses the costs incurred by the Company to obtain the ratepayer benefit, i.e. the lower maintenance fees.

18 Q. Is the Company revising its direct testimony estimate for the test year amortization  
19 amount on rebuttal?

20       A.    Yes. As a result of the Consumer Advocate's testimony with respect to this issue,  
21           the Company re-evaluated the two-year amortization period and concluded that  
22           amortizing the Ellipse maintenance buy-down fee over a period up to the next  
23           software upgrade, currently planned by the vendor for September 2007, is more

1           \$111,000 was allocated to Account 9302. As a result of the reduced test year  
2           amortization amount, there is a total net savings to the ratepayer of approximately  
3           \$54,000 per year. In other words, HECO's portion of the maintenance buy-down  
4           fee amortization and new lower annual maintenance fee is \$54,000 per year less  
5           than the previous total annual maintenance fee.

6           Account No. 931 – Rents Expense

7           Q.    What are the Company's test year estimate and the remaining differences between  
8           the Consumer Advocate with respect to Account No. 931 - Rents Expense?

9           A.    The Company's normalized test year 2005 estimate for Account No. 931 is  
10           \$2,201,000 after increasing its direct testimony estimate by \$644,000 (see HECO-  
11           R-1301). The Consumer Advocate, on the other hand, increased the Company's  
12           direct testimony estimate for Account No. 931 by \$601,000, which is lower than  
13           the Company's increase by \$43,000.

14          Q.    What makes up the \$43,000 difference in estimated rents expense?

15          A.    The \$43,000 difference in estimates between HECO and the Consumer Advocate  
16           is due mostly to a new operating lease agreement with Kamehameha Schools  
17           Bishop Estate effective July 2005.

18          Q.    Who presents the Company's position with respect to the treatment of the King  
19           Street office building lease agreement?

20          A.    Ms. Tayne Sekimura presents the Company's position in HECO RT-16. The  
21           Company has reduced its overall test year revenue requirements with respect to  
22           the King Street office building lease.

23          Q.    What is the revision with respect to the lease rent expense portion of the King  
24           Street office building revenue requirements included in Account No. 931?

25          A.    The Company's rebuttal testimony estimate for the King Street office building

1 rent is a net \$549,000 (after reimbursements from Hawaiian Electric Industries,  
2 Inc. (HEI)), compared to the direct testimony estimate of a net \$506,000, an  
3 increase of \$43,000.

4 Q. How did the Company calculate its revised King Street office building test year  
5 rent expense estimate?

6 A. The calculation is shown on HECO-R-1307. To summarize the calculation, the  
7 Company's test year rent expense estimate is based on six months of month-to-  
8 month rent incurred under the previous lease agreement (i.e. \$387,000 total from  
9 January to June 2005), six months of operating lease expense under the new lease  
10 agreement (i.e. \$440,000 total from July to December 2005), general excise tax of  
11 \$32,000, and rent reimbursements from HEI of \$310,000.

12 Q. Besides the treatment of the King Street Office building lease agreement which is  
13 addressed by Ms. Tayne Sekimura in HECO RT-16, are there any remaining  
14 differences between the Company and the DOD with respect to the test year  
15 estimates for Account No. 931- Rent Expense?

16 A. Yes, as shown in HECO-R-1301, the Company's rebuttal test year estimate for  
17 Account No. 931 is \$2,201,000 while the Department of Defense has apparently  
18 adopted the Company's direct testimony estimate of \$1,557,000, a difference of  
19 \$644,000 between estimates.

20 Q. Why is the Company's rebuttal testimony estimate more accurate and reasonable  
21 than its direct testimony estimate?

22 A. The Company's direct testimony estimate is not sufficient to cover the ongoing  
23 level of rent expense being incurred by the Company. In response to CA-IR-260,  
24 the Company presented revised rent expense estimates for Central Pacific Plaza  
25 and Pauahi Tower. Further explanation and documentation supporting the revised

1 rent expense estimates were provided in the Company's responses to CA-IR-617  
2 and CA-IR-618.

3 Q. What are the reasons for the revised rent expense estimates explained in the  
4 Company's responses to CA-IR-260, CA-IR-617 and CA-IR-618?

5 A. In response to CA-IR-260 the Company identified, by Responsibility Area (RA)  
6 code, the occupants of the leased square footage. In response to CA-IR-618, the

---

7 Company provided additional information regarding new office space in Pauahi  
8 Tower (at a cost of \$453,000 per year) which is being occupied by the Information  
9 Technology and Services Department. In its response to CA-IR-618, the  
10 Company explained its decision to relocate the Information Technology and  
11 Services Department due to the significant staff and operational growth in  
12 departments located at the Ward Avenue facilities. In its response to CA-IR-617  
13 the Company made available to the Consumer Advocate, Department of Defense  
14 and the Commission, the negotiated lease amendments and agreements supporting  
15 the revised rent expense estimates.

16

17 KAHE UNIT 7 PROJECT COSTS

18 Q. What is the difference between the Company and the Consumer Advocate and the  
19 Department of Defense with respect to the \$900,000 amortization of Kahe Unit 7  
20 Project costs included in HECO's test year Production Operation expenses?

21 A. In accordance with a stipulated agreement between the Company and Consumer  
22 Advocate, which was approved by the Commission in Decision and Order No.  
23 18872 filed on September 5, 2001, \$4.5 million of Kahe Unit 7 Project costs are  
24 being amortized over five years through September 2006, including the \$900,000  
25 of amortization included in the Company's test year 2005 estimate for Other

1 Production Operation expenses. The CA and DOD propose to revise and extend  
2 the amortization period for the expected December 31, 2005 balance of \$675,000  
3 to four full years beyond December 31, 2005, or \$169,000 per year through  
4 December 31, 2009 (see CA-T-1, pages 73-74 and CA Schedule C-8, lines 20-24;  
5 see DOD T-1, pages 31 and 32 and Exhibit DOD-120, lines 6 and 12). The  
6 difference in estimated test year 2005 expenses for the Kahe Unit 7 Project costs  
7 is, therefore, \$731,000 (\$900,000 less \$169,000).

8 Q. Why are the CA's and DOD's proposals (the proposals are the same) unacceptable  
9 to the Company?

10 A. The CA's and DOD's proposals are unacceptable for three reasons:

- 11 1) The proposals are inappropriate,
- 12 2) The proposals are inconsistent in that the CA and DOD use two different 2005  
13 amortization amounts in calculating their test year estimates,
- 14 3) The Company does not agree with the CA's and DOD's assumption that the  
15 rates established in this docket will be in effect for four years.

16 The Proposals are Inappropriate

17 Q. Why are the CA's and DOD's proposals inappropriate?

18 A. As the Consumer Advocate points out, the current treatment of the Kahe Unit 7  
19 project costs is the result of an earlier stipulated agreement between the Company  
20 and Consumer Advocate, which agreement was approved by the Commission. It  
21 is highly inappropriate for the Consumer Advocate (and DOD) to now unilaterally  
22 propose that the Commission modify, without HECO's approval, the previously  
23 established solution to the treatment of the Kahe Unit 7 project costs. An  
24 undesirable precedent, i.e. permitting unilaterally proposed changes to previously  
25 established and approved multi-party agreements, could be set if the Commission

1           were to adopt the Consumer Advocate's (and DOD's) proposal.

2           The Proposals are Inconsistent

3           Q.   Why are the CA's and DOD's proposals inconsistent?

4           A.   In calculating their proposed \$169,000 amortization amount for the Kahe Unit 7  
5           project costs, the CA and DOD assumed that the 2005 amortization amount will  
6           be \$900,000, i.e. they used the Company's test year estimate and what is actually  
7           being recorded. On the other hand, the CA's and DOD's proposed \$731,000  
8           adjustment to the Company's \$900,000 test year amount assumes that the 2005  
9           amortization will be only \$169,000.

10          A Four Year Amortization Period is Too Long

11          Q.   Why are the CA's and DOD's proposals to extend the amortization period to four  
12          full years beyond December 31, 2005 not acceptable to HECO?

13          A.   The Consumer Advocate's (and DOD's) proposed four year amortization period  
14          for the Kahe Unit 7 project costs appears to be based on its recommended four  
15          years for the amortization of rate case expenses as discussed previously in this  
16          testimony under Account No. 928 – Regulatory Commission Expenses. As  
17          explained in the previous testimony, based on current conditions, the Company's  
18          next rate case is more likely to be filed in three, rather than four, years after the  
19          conclusion of this instant proceeding.

20          Q.   Are you aware of any other differences between HECO and the CA and/or HECO  
21          and the DOD that should be addressed by the Company with respect to your areas  
22          of responsibility in this case?

23          A.   No, I am not.

24          Q.   Does this complete your rebuttal testimony?

25          A.   Yes, it does.

FAYE K. YAMAUCHI

Educational Background And Experience

Business Address:	Hawaiian Electric Company, Inc. 900 Richards Street Honolulu, Hawaii 96813
Current Position:	Director of Cost Accounting (December 1994 to Present)
Years of Service:	25 Years
Degree:	Bachelor of Business Administration University of Hawaii, 1977
Certification:	Certified Public Accountant (inactive) State of Hawaii
Previous Positions:	Administrator – Payroll & Disbursement Accounting (1991 – 1994)  Disbursement Accountant (1989 – 1991)  Accounting Systems Analyst (1988 – 1989)  Financial Analyst (1984 – 1988)  Budget Analyst (1981 – 1984)  Associate Staff Accounting Analyst (1979 – 1981)

HECO-R-1301  
DOCKET NO. 04-0113  
PAGE 1 OF 1

HAWAIIAN ELECTRIC COMPANY, INC.  
REBUTTAL ESTIMATES FOR ADMINISTRATIVE AND GENERAL EXPENSE ACCOUNTS

(\$ Thousands)								
	[A] HECO DT Est	[B] Adjustments	[C] Note	[D] = [A] + [B] HECO RT Est	[E] CA	[F] = [D] - [E] CA Diff	[G] DOD	[H] = [D] - [G] DOD Diff
ADMINISTRATIVE								
920 A&G Expense - Labor	13,925	(69)	1	13,856	13,605	251	13,460	396
921 A&G Expense - Non labor	11,578	(344)	2	11,234	10,778	456	11,489	(255)
922 A&G Expenses Transferred	(2,203)	17	3	(2,186)	(2,203)	17	(2,203)	17
Total Administrative	23,300	(396)		22,904	22,180	724	22,746	158
OUTSIDE SERVICES								
923010 Outside Services - Legal	154			154	154	0	154	0
923020 Outside Services - Other	898	381	4	1,279	1,278	1	1,279	0
Total Outside Services	1,052	381		1,433	1,432	1	1,433	0
INSURANCE								
924 Property Insurance	2,428	0		2,428	2,428	0	2,428	0
925 Injuries & Damages - Employees	6,036	0		6,036	6,036	0	6,036	0
Total Insurance	8,464	0		8,464	8,464	0	8,464	0
EMPLOYEE BENEFITS								
926000 Employee Pensions and Benefits	13,271	400	5	13,671	13,023	648	13,023	648
926010 Employee Benefits - Flex Credits	9,811	50	6	9,861	9,861	0	9,861	0
926020 Employee Benefits Transfer	(7,239)	(141)	7	(7,380)	(7,360)	(20)	(7,360)	(20)
Total Employee Benefits	15,843	309		16,152	15,524	628	15,524	628
MISCELLANEOUS								
928 Regulatory Commission Expenses	95	103	8	198	86	112	86	112
9301 Inst. or Goodwill Advertising Expense	73			73	73	0	73	0
9302 Miscellaneous General Expenses	3,319	(207)	9	3,112	2,902	210	3,223	(111)
931 Rents Expense - A&G	1,557	644	10	2,201	2,160	41	1,557	644
932 Admin and General Maintenance	740			740	740	0	740	0
Total Miscellaneous	5,784	540		6,324	5,961	363	5,679	645
TOTAL ADMINISTRATIVE & GENERAL EXPENSES	54,443	834		55,277	53,561	1,716	53,846	1,431
Note	Amount		Reference					
1	920	Customer Solutions reorganization	-69	CA-IR-78				
2	921	Remove HR/Suites Amortization	-184	CA-JR-352				

Hawaiian Electric Company, Inc.  
Net Additional Positions Not Reflected in the 2005 Test Year Forecast and  
Plans to Fill Current Vacancies

**Corporate Audit & Compliance**

**Additional Positions:**

As a public Company, HECO and its subsidiaries are required to file various periodic reports with the Securities and Exchange Commission and to strictly comply with the requirements of the Sarbanes-Oxley Act of 2002 (SOX). The SOX Compliance Division was added in 2004 to comply with the on-going requirements of SOX Sections 404 and 302, which entailed a need for annual company-wide audits of internal controls over financial reporting. In addition, a new Corporate Audit and Compliance department was formed in 2004 to oversee the Internal Audit and SOX Compliance Divisions. The new Manager of this Department will direct company-wide audit and compliance initiatives

---

and programs for effecting corporate risk management, addressing emerging requirements and assessing compliance with applicable laws, regulations and corporate policies and procedures.

As a result of the changes described in the preceding paragraph, six additional positions were approved, which were not included in the TY 2005 forecast. Labor for these positions is charged to O&M. The positions are Corporate Compliance Analyst; SOX Compliance Specialist (2); Director SOX; Secretary; and Manager, Corporate Compliance & Audit. Subsequent to June 30, 2005, the Department Secretary will be transferring to another position within the Company. The Department anticipates not filling the position until 2006, resulting in a net increase of 5 approved positions in 2005.

**Plans to Fill Current Vacancies:**

As of June 30, 2005, there were three vacancies in the Internal Audit Division. The Division has been currently recruiting for the Internal Audit-Director position since the beginning of 2005 but has not been able to fill this position. In a move to better serve the needs of this Division and fill the gaps in IT audits, the IA Director position will be

positions is charged to the ISD Clearing Accounts. The O&M impact after clearing is 0.2% as stated in the Company's comments to CA ID 605

A number of new IT network-related initiatives and associated support requirements have created a workload that presently exceeds the department's ability to match Company requirements and its capacity to manage external contractor/consultant support. Serious concerns have been raised by our user-departments about quality and meeting deadlines for Company moves/changes, expanding business telecommunications, security division needs, LAN/network device growth, growth of server-based business and technical applications, wireless/mobile support, etc. The department is also faced with meeting stringent external and internal security compliance requirements stemming from recent detailed IT security audits, Sarbanes-Oxley risk assurance requirements, and other sound operational requirements. Its work requests have grown by over 10% per year over the past several years without a corresponding increase in staffing.

Plans to Fill Current Vacancies:

There are currently five open positions. The status of these five positions is as follows:

IT Project Manager: Scheduling interviews. Expect to fill within six weeks.

Development Analyst: JVR/JVN approved 7/27/05

IT Desktop Specialist: JVN/JVR approved; vacancy occurred in July 2005

FVM Specialist: JVR/JVN soon to be submitted; vacancy occurred in July 2005.

IT Infrastructure Specialist: Gone through two rounds of interviews but a suitable

### **Workforce Staffing & Development**

#### **Additional Positions:**

The Director, Client Services & Consulting Division position was not included in the test year 2005 forecast but has been filled since July 2004. This new position was established to develop short- and long-range strategic plans for effective staffing, development and utilization of highly-qualified employees. A significant portion of the work in the division is transactional and must meet compliance reporting requirements. This position was needed to direct the daily operations of the division to ensure the relevant processes and activities are in compliance with State and Federal laws and run smoothly. In addition, the Director will review all internal EEO complaint investigations and disciplinary actions involving salaried employees. Labor for this position is charged 100% to O&M.

#### **Plans to Fill Current Vacancies:**

As of June 30, 2005, the HR Assistant position is vacant. A candidate to fill the vacancy has been identified and a job offer will be made once the approval to hire is received. Although the anticipated increase in the number of tests for entry-level positions and testing requirements and increased workload in other areas may justify an additional 2 ½ more positions in 2006, the department plans to have an employee count of 17 for 2005.

### **Government Relations**

#### **Additional Positions:**

The Manager, Government Relations position was not included in the 2005 test year forecast but has been filled since December 2004. This position is responsible for maintaining effective relations with legislators on issues affecting the electric utility. A written position description was provided in the Company's response to CA-IR-513. Based on the labor charges to date for this position, approximately 92% is charged to O&M, 1% to capital, and 7% to billables.

### **Education & Consumer Affairs:**

#### **Additional Positions:**

An additional Education & Community Affairs Administrator was hired in May 2005 but was not included in the 2005 test year forecast. This position is a restoration of a position that was previously frozen and charges 100% to O&M. This position will help the department handle the traditional activities (Electron Marathon and Electric Kitchen) as well as the increasing focus on Education & Consumer Affairs activities in the West Oahu/Leeward Coast area.

### **VP-Government & Community Affairs:**

#### **Additional Positions:**

The Community Relations Coordinator and the Public Affairs Specialist positions were not included in the 2005 test year forecast but have been filled since October 2004 and September 2004, respectively. The staffing plans and objectives for this department were presented in the Company's response to CA-IR-511. The hiring of the Public Affairs

Specialist replaced the forecasted position in the Corporate Communications Division (as previously presented in the Company's response to CA-IR-486) resulting in a net increase of one position in the VP Government and Community Affairs area.

**Regulatory Affairs**

**Additional Positions:**

There is a new Regulatory Analyst II position that was filled in May 2005 but was not included in the 2005 test year forecast. This position was needed to handle the increased workload of the Regulatory Affairs Division to support the Company's regulatory filing and approval requirements. Labor for this position is charged to O&M.

**Plans to Fill Current Vacancies:**

As of June 30, 2005, there was one vacancy in the division for a Regulatory Analyst. This position was included in the 2005 test year forecast as a Bargaining Unit Clerk. However due to the increased workload in this division, the Bargaining Unit Clerk position was replaced with a Regulatory Analyst position. The division has posted this position and is searching for qualified applicants. This position is anticipated to be filled in the fourth quarter of 2005, bringing the division's employee count to eight by the end of the year.

**Technology**

**Additional Positions:**

A Project Aide position was approved for hiring and filled in March 2005. This position was not included in the 2005 test year forecast. The Project Aide basically assists the Technology Division in renewable energy activities and other general engineering activities and works part-time during the school year and full-time during the summer. This position is currently scheduled for a two year period and charges 100% of its labor charges to O&M.

Hawaiian Electric Company, Inc.  
Allocation of Ellipse Software Maintenance Fees  
Test Year 2005 Estimate

		Result	Allocated Amount					NARUC
		Alloc	HECO-1604	ADJ	Rebuttal	CA Position	Difference	Acct
		[a]	[b]	[c]	[b]-[c] = [d]	[e]	[d]-[e] = [f]	
			549,664	(194,444)	355,220	148,625	206,595	
<b>Work Management Amortization</b>								
<b>Capital Expenditures</b>								
212	212 Constr Proj - Prod	0.007390	4,061.76	(1,436.85)	2,624.91	1,098.27	1,527	514
320	320 Manage Trans Construction Proj	0.021963	12,072.45	(4,270.64)	7,801.82	3,264.30	4,538	566
420	420 Manage Distri Construction Proj	0.073280	40,279.12	(14,248.77)	26,030.36	10,891.17	15,139	598
<b>Production</b>								
<b>Prod Operation</b>								
245	245 Monitor Plt Oper Perf - Boiler	0.011809	6,490.94	(2,296.18)	4,194.77	1,755.10	2,440	502
246	246 Monitor Plt Oper Perf - Turbo Gen	0.009819	5,397.23	(1,909.27)	3,487.96	1,459.37	2,029	505
<b>Prod Maint</b>								
258	258 Maint Bir Plt & Rel Equip - Predictive	0.014940	8,212.23	(2,905.08)	5,307.15	2,220.52	3,087	512
261	261 Maint Strm Turbo Gen & Rel Equip Predictive	0.008964	4,927.34	(1,743.05)	3,184.29	1,332.31	1,852	513
<b>Transmission and Distribution</b>								
<b>Transmission</b>								
<b>Transmission Operation</b>								
331	331 Oper Trans Fac - OH Line	0.002563	1,408.67	(498.32)	910.35	380.89	529	563
333	333 Oper Trans Fac - Substation	0.002646	1,454.48	(514.52)	939.96	393.28	547	562
<b>Transmission Maint</b>								
343	343 Maint Trans OH Line - Predictive	0.003504	1,926.10	(681.36)	1,244.74	520.80	724	571
349	349 Maint Subst Trans Equip - Predictive	0.001634	898.10	(317.70)	580.39	242.84	338	570
<b>Distribution</b>								
<b>Distribution Operation</b>								
461	461 Oper Distri Fac - OH Line	0.003427	1,883.78	(666.39)	1,217.39	509.36	708	583
462	462 Oper Distri Fac - UG Line	0.003782	2,078.86	(735.40)	1,343.46	562.11	781	584
463	463 Oper Distri Fac - Substation	0.003882	2,133.73	(754.81)	1,378.92	576.94	802	582
<b>Distribution Maint</b>								
474	474 Maint Distri OH Line - Predictive	0.006117	3,362.06	(1,189.33)	2,172.73	909.08	1,264	593
477	477 Maint Distri UG Line - Predictive	0.005907	3,246.66	(1,148.51)	2,098.15	877.87	1,220	594
486	486 Maint Subst Distribution Equip - Predictive	0.001974	1,084.78	(383.74)	701.04	293.32	408	592
<b>Accounting/Finance</b>								
818	818 Maintain General Ledger, Subledgers, & Statistical Information	0.375700	206,508.76	(73,052.61)	133,456.15	55,838.41	77,618	[a] 9302
<b>HR/Payroll</b>								
766	766 Maintain Employee Records	0.007645	4,201.96	(1,486.45)	2,715.51	1,136.18	1,579	[b] 921
777	777 Process Payroll	0.238955	131,345.18	(46,463.44)	84,881.74	35,514.75	49,367	[b] 921
<b>Materials</b>								
842	842 Order Materials, Equip., Supplies	0.019410	10,668.98	(3,774.16)	6,894.82	2,884.81	4,010	[a] 9302
843	843 Process Invoice & Other Payments	0.125971	69,241.67	(24,494.29)	44,747.38	18,722.43	26,025	[a] 9302
850	850 Process Materials & Transaction	0.048719	26,779.14	(9,473.14)	17,306.00	7,240.88	10,065	[a] 9302
<b>TOTAL (HECO's portion of the MINCOM software maintenance fees)</b>			549,664	(194,444)	355,220	148,625	206,595	
[a] Amt allocated to acct 9302			313,199	(110,794)	202,404	84,687	117,718	
[b] Amt allocated to acct 921			135,547	(47,950)	87,597	36,651	50,946	

HECO

Revised Calculation of the Ellipse Buy-Down Fee Amortization for TY 2005

	TOTAL	HECO's portion (70%)
Buy-Down Fee (1.1 mill x1.04166)	1,145,826	802,078
Amortization in 2004		
June-Dec 2004: 47,743/mo	334,201	233,941
Unamortized Balance, 12/31/04	811,625	568,138
Remaining Life: 1/05-9/07	33	33
Monthly Amortization	24,594.70	17,216.29
Revised Annual Amortization	295,136.36	206,595.45
Direct Testimony: HECO-1604 (47,742.75*12)	572,913.00	401,039.10
Downward Adjustment	(277,776.64)	(194,443.65)

Net Savings to Ratepayers:

Amortization of buydown	295,136.36	206,595.45
Ellipse Maintenance fee "new" (187,000*1.04166)	194,790.42	136,353.29
	489,926.78	342,948.75
Ellipse Maintenance fee "old" (545,003*1.04166)	567,707.29	397,395.10
Net "savings"	(77,780.51)	(54,446.35)

HECO-R-1304  
DOCKET NO. 04-0113

HAWAIIAN ELECTRIC COMPANY, INC. PAGE 1 OF 2  
ADMINISTRATIVE GENERAL EXPENSES TRANSFERRED  
ACCOUNT 922

**2005**  
**(000)**

**Cost Pool:**

Labor		\$ 1,453	
Transfer Rate per updated KPMG study	X	<u>39%</u>	\$ 567
NPW			77
Payroll Taxes			48
Emp Ben			162
Nonlabor-Acct. 921.00		\$ 11,083	
Transfer Rate per updated KPMG study	X	<u>5%</u>	\$ 554
Capital Budgets Labor			127
NPW			15
Payroll Taxes			11
Emp Ben			32
	A		<u>\$ 1,592</u>

**Cost Base:**

Capital Labor Hours		\$ 452	
Clearings to Capital	+	<u>210</u>	\$ 662
	B		
Corporate Admin rate per hour	C = A ÷ B		\$ 2.40
Total Productive hours	D X	<u>3,022</u>	
Administrative Expenses Transferred - based on total productive hours	E = C X D		\$ 7,253
Reversal of Corporate Admin on-cost charged to O&M	+	<u>(5,079)</u>	
Subtotal			\$2,174

HAWAIIAN ELECTRIC COMPANY, INC. PAGE 2 OF 2  
ADMINISTRATIVE GENERAL EXPENSES TRANSFERRED  
ACCOUNT 922

2005  
(000)  
\$2,174

Subtotal from page 1

Administrative Expenses Transfer Adjustments and  
Normalizations:

Abandoned Capital Project adjustment	56
Ellipse Upgrade normalization	39
Incremental IRP normalization	560
Human Resources Suite project amortization adjustment	184
Correction for eBusiness erroneously excluded from Cost Pool	(284)
Correction for Recognition Awards erroneously included in Cost Pool	27
	<u>582</u>
Transfer Rate per updated KPMG study	X <u>5%</u>

29

Administrative Expenses Transfer Rebuttal  
Adjustments and Normalizations:

Remove HR/Suites Amortization	(184)
Increase HEI charges	99
Decrease HEI charges to 184120	(17)
Decrease charges in 184120 related to new phone system	(194)
Adjust Ellipse buy-down fee amortization	(47)
	<u>(343)</u>
Transfer Rate per updated KPMG study	X <u>5%</u>

(17)

Administrative Expenses Transferred

\$ 2,186

HAWAIIAN ELECTRIC COMPANY, INC.

ACCOUNT 926020

<u>Cost Pool:</u>	2005 <u>(000)</u>
Labor to 926	\$ 554
NPW	69
Payroll Taxes	46
Eng Del	0
Corp Admin	43
Stores	9
Emp Ben	144
Nonlabor	23,293
A	<u>\$ 24,158</u>

<u>Cost Base:</u>	
Total Company Productive Hours	3,022
B	<u>3,022</u>

HAWAIIAN ELECTRIC COMPANY, INC.  
EMPLOYEE BENEFITS TRANSFER  
ACCOUNT 926020

		2005 (000)
From page 1		\$ 7,239
Employee Benefits rebuttal adjustments and normalizations:		
926000 Qualified Pension Plan		239
926000 Other Postretirement Benefits		311
926000 Long-Term Disability Benefits		-86
926000 Delete 401(k) adm expenses		-51
926000 Delete HEI 401(k) adm expenses		-28
926000 Increase in HEI charges		13
926000 Long term care		2
926010 Flex Credits Less Prices		168
926010 Group Medical Plan		-319
926010 Group Dental Plan		39
926010 Group Vision Plan		-5
926010 Group Life Insurance Plan		112
926010 Other/Administration		55
Total rebuttal adjustments and normalizations	G	450
Employee benefits transfer ratio:		
Direct testimony acct 926000	H	13,271
Direct testimony acct 926010	I	9,811
Direct testimony acct 926020	J	-7,239
$K = (-1 \times J) / (H + I)$		0.313621003
Employee benefits transfer related to rebuttal adjustments and normalizations	$L = G \times K$	141
Total employee benefits transfer - Rebuttal Testimony	$M = F + L$	<u>\$ 7,380</u>

Hawaiian Electric Company, Inc.  
Account 928 - Regulatory Commission Expenses  
Test Year 2005 Estimate  
(\$ in 1000s)

	[a]	[b]	[a]+[b] = [c] HECO Rebuttal	[d] CA/DOD Position	[c]-[d] = [e] Difference
	HECO-1603	Adjustment			
Legal Fees	\$205	\$172	\$377	\$205	\$172
Consultant - Rate Design	30	(30)	-	-	-
Consultant - Return on Equity	30	29	59	59	-
Consultant - Rate of Return on Rate Base	-	40	40	40	-
Consultant - DSM	-	80	80	-	80
Stenographer	10	-	10	10	-
Consultant - HEI impact (affidavit)	8	8	16	16	-
Supplies	1	2	3	3	-
Printing Services	-	10	10	10	-
Total 2005 Rate Case Expenses	\$284	311	\$595	\$343	\$252
Amortization period (2005-2007)	3 years		3 years	4 years	
2005 amortization	<u>\$95</u>		<u>\$198</u>	<u>\$86</u>	<u>\$112</u>

Hawaiian Electric Company, Inc.  
Account 931 - Rent Expense  
Test Year 2005 - Rent

	[a]	[b]	[c]	[d]	[a]x[b]x12 + [c]x[d]x12 =[e]	[f]	[g]	[h]	[e]+[f]+[g]+ [h]+[i] x.04167=[j]	[e]+[f]+[g]+ [h]+[i]+[j] = [k]	[l]	[k] - [l] = [m]
EXISTING LEASES	Net sq ft	Monthly Rent per sq ft	Gross sq ft	Monthly CAM <sup>(1)</sup> per sq ft	Annual Rent (incl CAM)	Annual Real Prop Tax Credit	Op Exp Recon	Misc Exp <sup>(4)</sup>	Annual Gen Excise Tax	Annual Rent TY 2005 Rebuttal \$ in 1000's	CA Position CA 101 \$ in 1000's	Difference \$ in 1000's
Central Pacific Plaza (CPP)												
Suite 700 <sup>(2)</sup>	7,598	1.35	7,598	0.975	211,984	(16,608)	2,649	144	8,258	206	206	0
Suite 1010	3,930	1.43	4,509	0.975	120,194	(9,864)	1,572	144	4,669	117	117	0
Suite 1020, 1025 & 1075	3,947	1.44	4,532	0.975	121,229	(9,912)		144	4,645	116	116	0
Suite 1201 & 1212 <sup>(3)</sup>	2,500	1.44	2,871	0.975	16,126	(1,320)	210	30	627	16	16	0
Suite 1250 & 1270 <sup>(3)</sup>	1,464	1.36	1,598	0.975	8,944	(733)		30	343	9	9	0
Suite 1300 <sup>(2)</sup>	9,601	1.35	9,601	0.975	267,868	(20,988)	3,348	2,808	10,544	264	264	0
Suite 1425	2,404	1.45	2,788	0.975	74,449	(6,096)		144	2,854	71	71	0
Suite 1480	1,085	1.43	1,242	0.975	33,150	(2,712)	433	144	1,292	32	32	0
Suite 1515	637	1.44	732	0.975	19,572	(1,596)	255	144	766	19	19	0
Suite 1520 & 1530 <sup>(2)</sup>	2,139	1.55	2,451	0.975	68,462	(5,364)	855	144	2,671	67	67	0
Suite 1570	2,594	1.43	2,969	0.975	79,250	(6,492)	1,035	144	3,081	77	77	0
HEIPC Sublease <sup>(5)</sup>			1,537	0.975	41,928	(3,360)	536	56	1,632	41	41	0
Total - CPP										1,035	1035	0
King Street <sup>(6)</sup>	see calculation below									549	506	43
Honolulu Club		2.45	2,544		74,794				3,117	78	78	0
Pacific Tower 8th floor										54	54	0
Waiau Viaduct <sup>(7)</sup>										32	32	0
Pauahi Tower										453	453	0
										2,201	2158	43

(1) CAM = Common Area Maintenance

(2) Rents are proposed and awaiting landlord approval.

(3) CPP 12th floor: Lease rent is allocated 21% to O&M and 79% to DSM.

(4) Additional expense per month for miscellaneous key and card charges & after Hr. A/C for Suite 1300.

(5) HEIPC Sublease is 39% of HEIPC's total agreement. The amount per HEI should be \$43,000 instead of \$41,000

(6) King Street rent:

Rent	827,212	6 months of month-to-month \$387,500 (1/05-6/05) & 6 mo new operating lease \$439,712 (7/05-12/05)
GIT on Lease Payments	32,294	
less: HEI rent	(310,344)	[4]
Annual rent	549,162	

HEI rent:

Total King St. lease payments	859,504	[1]
Total bldg sq ft	58,313	[2]

Monthly Base rent/sq ft 1.23 [1] / [2] / 12

Monthly CAM 1.50 represents the estimated costs of operating expenses per sq. ft.

PSC tax and PUC fees 0.19 (1.28+1.50) x .0682\*

2.91

HEI sq ft x 8,874 \* .0682 represents the composite PUC Fees and PSC Taxes rate

Monthly HEI rent 25,862 [3]

Annual HEI rent 310,344 [3] x 12 = [4]

(7) Quarterly payment (\$7,925 x 4 x .001 = \$32,000)

(8) Additional expense related to "after-hour" air-conditioning charges (estimate \$222 / month)

Note: Numbers may not add exactly due to rounding.

REBUTTAL TESTIMONY OF  
RUSSELL R. HARRIS

DIRECTOR  
RISK MANAGEMENT  
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Insurance as included in Administrative and General Expenses

## INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Russell R. Harris, and my business address is 220 South King Street, Honolulu, Hawaii.

Q. What is your position with Hawaiian Electric Company, Inc. ("HECO")?

A. I am the Company's Director, Risk Management. My educational background and experience are shown in HECO-1400.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted written direct testimony, exhibits, and supporting work papers as HECO T-14.

Q. What are your areas of responsibility with respect to this case?

A. My testimony in HECO RT-14 will cover estimates of the Company's normalized test year 2005 estimates for insurance expense. These costs are included in administrative and general ("A&G") expenses addressed by Ms. Faye Yamauchi in HECO T-13 and HECO RT-13.

**Q. What is the scope of your rebuttal testimony?**

A. My rebuttal testimony will summarize the insurance costs as presented in HECO T-14 of this docket. These costs were not contested by CA-T-2 or by DOD-T-1 (See HECO-R-1401, page 1).

## INSURANCE

**Q. What are the accounts and test year 2005 amounts for insurance?**

A. As shown in HECO-1401, page 1, the insurance and the associated test year 2005 amounts totaling \$8,464,000 are as follows:

1	<u>Acct. No.</u>	<u>Description</u>	<u>Test Year 2005 Estimate</u>
2	924	Property Insurance	\$2,428,000
3	925	Injuries and Damages	6,036,000
4		Total	\$8,464,000
5			

6 Q. Have these amounts changed since your direct testimony, HECO T-14?

7 A. No.

8

9 CONCLUSION

10 Q. Please summarize your rebuttal testimony regarding the test year 2005 premium-  
11 related expenses, safety program costs, and absorbed losses estimates for Account  
12 Nos. 924.00, 925.01, and 925.02.

13 A. Insurance is a necessary cost of doing business. The costs related to securing  
14 reasonable levels of coverage should be included in the electric rates charged to  
15 the Company's customers. Therefore, the following premium-related expenses.

16 safety program costs, and absorbed losses should be included in the calculation of  
17 HECO's test year 2005 revenue requirements upon which electric rates will be set:

18 1) \$2,428,000 for Account 924, Property Insurance

19 2) \$6,036,000 for Account 925, Injuries and Damages

20 Q. Does this conclude your rebuttal testimony?

21 A. Yes.

22

23

**Hawaiian Electric Company, Inc.**

Type of Expense	HECO 2005 Test Yr Est	CA Position	DOD Position
<b><u>ACCOUNT 924.00. PROPERTY</u></b>			
Labor	185.3	185.3	185.3
Non-Labor	2,323.4	2,323.4	2,323.4
Less: G/L Code	<u>(80.3)</u>	<u>(80.3)</u>	<u>(80.3)</u>
Total Non-Labor	2,243.1	2,243.1	2,243.1
Combined 924	2,428.4	2,428.4	2,428.4
<b><u>ACCOUNT 925.01. INJURIES &amp; DAMAGES - EMPLOYEES</u></b>			
Labor - Workers' Compensation	279.4	279.4	279.4
Labor - Safety Program	<u>781.5</u>	<u>781.5</u>	<u>781.5</u>
Subtotal	1,060.9	1,060.9	1,060.9
Non-Labor - Workers' Compensation	1,527.1	1,527.1	1,527.1
Non-Labor - Safety Program	<u>1,090.5</u>	<u>1,090.5</u>	<u>1,090.5</u>
Subtotal	2,617.6	2,617.6	2,617.6
Combined 925.01	3,678.5	3,678.5	3,678.5
<b><u>ACCOUNT 925.02. INJURIES &amp; DAMAGES - PUBLIC</u></b>			
Labor - Liability	297.8	297.8	297.8
Non-Labor - Liability	<u>2,593.2</u>	<u>2,593.2</u>	<u>2,593.2</u>
Combined 925.02	2,891.0	2,891.0	2,891.0
<b><u>COMBINED ACCOUNT 925. INJURIES &amp; DAMAGES</u></b>			
Total Labor 925	1,358.7	1,358.7	1,358.7
Total Non-Labor 925	5,210.8	5,210.8	5,210.8
Less: G/L Codes	<u>(534.0)</u>	<u>(534.0)</u>	<u>(534.0)</u>
Total Non-Labor 925	4,676.8	4,676.8	4,676.8
Combined 925	6,035.5	6,035.5	6,035.5
GRAND TOTAL	<u>8,463.9</u>	<u>8,463.9</u>	<u>8,463.9</u>